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PAGE 79

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JULY
1960

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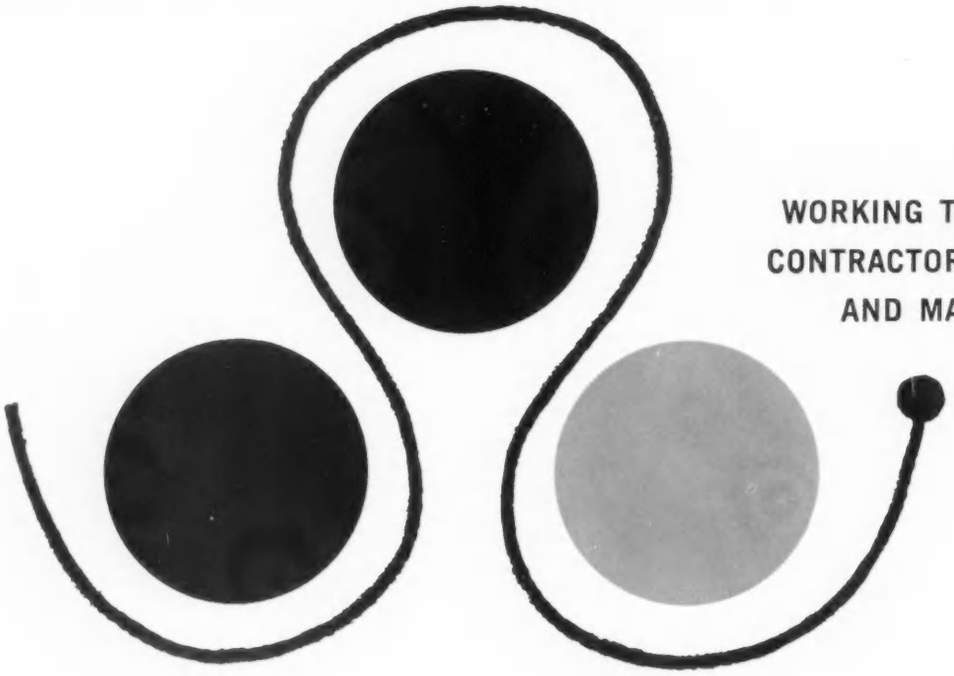

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WORLD OIL

A Gulf Publishing Company Publication

SPECIALIZED FOR EXPLORATION, DRILLING AND PRODUCING OPERATIONS AND MANAGEMENT

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A Quick Look

at this issue

BUSY OIL MEN: To help you put first things first, scan these time-saving digests on this and the following pages, checking [√] those you want to read first.

☐ **Sun ray completes world's first sextuple well . . .** The producing industry's first small diameter sextuple well has recently been completed in North Laward field, Jackson County, Texas by Sunray Mid-Continent Oil Company. Three strings of 2⅞-inch tubing were run as casing and two zones were perforated in each string. 1½-inch tubing then was installed and packed off between producing intervals. Thus, each 2⅞-inch string produces as an "old style" dual completion, one zone flowing through the 1½-inch pipe and the other through the 2⅞-1½-inch annulus. Complete details and all equipment used in this unique well are included in the article starting on ..... **Page 79**

☐ **Why drill for offshore oil? . . .** Louisiana operators are digging deep for an answer to this question. What is the significance of the state's multiple completion ruling? Who is affected? What was the status of offshore operations at the time of the ruling? You will find the answers to these questions, plus a candid evaluation of the pros and cons of offshore operations, starting on **Page 86.**

☐ **Prospects brighten for California heavy crude producers . . .** California producers currently are enjoying a turnabout in the marketing of their heavy crude. The long-depressed segment of the industry is cheered by new longer-term contracts being written by at least one major purchaser. Discounted crudes now are being taken at posted prices in many instances and the gap between offered and posted price is diminishing steadily. For a quick review of the changed situation and a glimpse into some long term problems that may be

WORLD OIL published every month except semi-monthly in February and August. Second class postage paid at Houston, Texas. ©Gulf Publishing Co. 1960

presented if excessive quantities of gas are imported into the state, turn to.....**Page 90**

☐ **Unique gas lift hook-up used to dewater gas wells . . .** Colorado Oil and Gas Corporation has successfully used a simple, closed rotative gas lift system to dewater gas wells in the Mid-Continent area. A 170 Mcfd capacity, skid mounted compressor, 500 psi separator, and two gas lift lift valves run on one-inch line pipe complete the installation. Wells are easily kept free of water, gas production remains stable, and no gas is vented to atmosphere or wasted at any time. The only gas consumed on the lease is the 4 Mcfd required for compressor engine fuel. For complete details of this unusual installation, see.....**Page 92**

☐ **Three eighths of U. S. oil produced by independents.** As in recent years, smaller companies and operators in 1959 accounted for about three out of every eight barrels of crude oil production in the United States. Their share was, however, slightly less than in 1958. Texaco Inc. for the second year was the foremost domestic producer. Standard Oil Company (N. J.) continued second. It had been first in 1957. Gulf remained third and Shell fourth. See.....**Page 95**

No apathy here!

IF RESPONSE to WORLD OIL's June report on "Oil and Gas in Politics" is any indication, there is no apathy among our readers in this presidential election year.

Large quantity orders for more than 15,000 reprints have been received to date, plus scores of individual orders. And the response has just started coming in.

As you recall, the June report included an eight-page analysis of the critical oil and gas issues facing Congress next year—voting records of potential presidential and vice presidential candidates—plus, voting records of 30 senators who are seeking re-election this year.

If you haven't done so already, there still is time to inform yourself and your friends about the issues and voting records that will affect the future of your industry.

"Oil and Gas in Politics" reprints are available at following prices: 1-14 copies, 25 cents each; 15-49 copies, 20 cents each; 50-99 copies, 15 cents each. Special prices will be quoted for orders of 100 or more.

Send your order and remittance to: Reprint Department, Gulf Publishing Company, P.O. Box 2608, Houston, Texas.

Fishing manual in August

ENGINEERING EDITOR JACK EARL is putting finishing touches on WORLD OIL's second Engineering Practices Manual, covering every aspect of fishing operations. It now is being reviewed by top fishing authorities.

The first part of the manual will be published in the August 1 issue, and will include in its entirety:

- More than 60 pages describing typical fishing conditions—tools that are used—plus, a step-by-step description of how fish are recovered.
- More than 50 illustrations of the most modern tools and methods.

Authorities reviewing the manual say it will provide the most thorough coverage published to date on fishing operations.

You will, too.

☐ **Independents have big market for crude . . .** Strictly producing companies and independent operators in 1959 found a market for 2,823,904 barrels daily of domestic crude at plants of large and small refining companies. This large market was available despite petroleum imports and the major companies' own domestic crude production. The crude provided by the non-integrated producing companies was equivalent to 35.3% of all crude run to stills at U. S. refineries and to 40.2% of all domestic crude processed. See.....**Page 96**

☐ **How to cement dual tubingless completions . . .** Heretofore, on tubingless dual completion wells, communication between the two producing zones have been very prevalent. However, with the new cementing techniques of reciprocating the pipe while cementing, Phillips Petroleum Company has eliminated this continuing difficulty. See **Page 97** which discusses techniques that were used to achieve this success.

☐ **Practical field techniques cut crude treating costs . . .** Oil treating costs can be cut substantially, particularly in cold weather areas by reducing heater-treater operating temperatures and proper use of chemicals. Application of these practical operating procedures and recognition of different types of treating problems, can result in increased stock tank oil recovery and reduced operating and maintenance costs. For more information on how to cut treating costs in cold weather areas, turn to.....**Page 100**

☐ **Arctic Islands allow rapid evaluation by photogeology . . .** Mobile belts in the Canadian Arctic Islands contain thousands of feet of sediments. More than 40 piercement domes have been identified. Pronounced structural and stratigraphic features are readily mapped from aerial photographs. Considerable air photo cover-

Watch for your International Outlook

age is available pursuant to work done previously by the Royal Canadian Air Force and the Geological Survey of Canada, and coverage is being improved. Despite the brevity of the sumer field work season, quick and effective geologic analysis of the Canadian Arctic Islands is at hand. See..... **Page 103**

☐ **Persian Gulf weather forecasting system developing rapidly . . .** Assembly and movement of offshore drilling platforms is becoming much safer now that an integrated system of weather stations has been set up by oil companies operating in the Persian Gulf. Triggered by the loss of several lives, an expensive mobile offshore drilling outfit, and three years' delay in the exploration program of one company, the new weather forecasting grid is continually gaining new stations and is unveiling the secrets of treacherous Persian Gulf winds and tides. See..... **Page 108**

☐ **How to control blowouts (Part 3) . . .** From 50 to 70 percent of all blowouts occur while making a trip. In the last part of this popular series, the author discusses control of such blowouts in detail, including proper gel strength and keeping the hole filled, plus a five-step procedure for killing blowouts..... **Page 111**

☐ **How to design a closed rotative gas lift system (Part 1) . . .** This first of a two-part series of articles on closed rotative gas lift systems describes the step-by-step calculations required. The following considerations required for continual operation of a closed rotative system without make-up gas after initial charging are discussed—estimation of daily injection gas requirement for assumed injection gas pressure—calculation of approximate compressor brake horsepower—design of the high pressure injection gas system—calculation of excess or make-up gas volume—and design of the low pressure gas gathering system. For complete details, see..... **Page 116.**

☐ **How to get top performance from your V-belt drives . . .** Multiple V-belt drives are accepted as trouble-free method of mechanical power transmission. This condition will continue as long as the belts are used as matched sets, installed properly, inspected at regular intervals, and stored in the proper manner when not in use. See **Page 120** which discusses these various phases for maintaining efficient use of V-belt type drives.

☐ **How to choose eastern Oklahoma datum planes . .** Rapid lower Pennsylvanian facies changes in general and highly lenticular sandstones in particular make selection of workable datum planes a difficult and crucial problem for subsurface geologists working in the McAlester Basin. This article, written by a well-known consulting geologist, shows stratigraphic relationships in a series of maps and cross-sections. Specific markers, e.g., Oswego, Verdigris, "Pink", Inola and Brown limestones are discussed on their merit as markers. See... **Page 124**

Issue August 15

Oil Industry In Brief

Here are the latest industry trends, revealed by WORLD OIL and industry research:

Demand increases. Petroleum product demand took sharp upward turn in May and early June. May totals were at all-time high, up 9.3 percent over same 1959 period . . . See Page 25.

Crude production down. Strict proration held May crude production 5.7 percent under May 1959, making it possible to hold new supply 1.6 percent under May last year . . . See Page 25.

Imports up sharply. May crude oil imports were up 6.5 percent from year ago levels, product imports were up 22.6 percent, for total increase of 12.4 percent . . . See Page 25.

Well completions increase. May completions averaged 134 wells per day, up 17.8 percent from April's 118 wells per day . . . See Page 28.

Rig totals remain low. On May 31, 3,752 rigs were operating in the U.S., up 24 over April 30 total. However, May total was 533 rigs under 4,285 reported at May's end 1959 . . . See Page 28.

New depletion attacks. Anti-depletion move in Senate continues full steam. Look for new roll call vote in near future, with vicious attacks from Senators Williams (R-Del.), Young (D-Ohio), Morse (D-Ore.), Douglas (D-Ill.), Proxmire (D-Wis.) . . . See Page 13.

Offshore operators hurt. Louisiana multiple completion order in June was serious blow to offshore operations. High percentage of offshore wells are multiple—operators cannot afford to make single completions . . . See Page 86.

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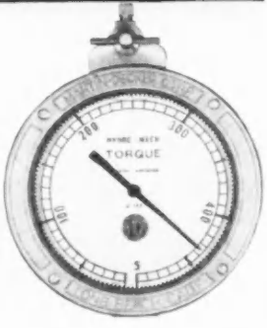

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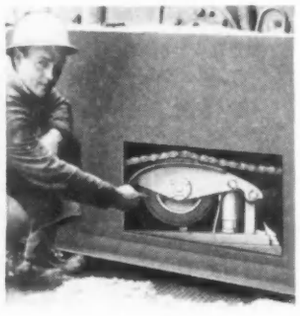

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WORLD OIL (formerly The Oil Weekly) and The COMPOSITE CATALOG for the drilling-producing industry.

PIPE LINE INDUSTRY and The PIPE LINE CATALOG for the oil and gas pipe line industry.

PETROLEUM REFINER and The REFINERY CATALOG for the oil, gas and petrochemical processing industry.

Indexed by Industrial Arts Index and Engineering Index

Looking Ahead

Oil and gas in politics . . . At June 19 news conference in Houston, Vice President Richard Nixon announced support of 27½ percent depletion provision and natural gas bill that would free producers from federal control at wellhead.

Reports are, Texas GOPers want percentage depletion and natural gas bill included in party platform. Most Democratic candidates would prefer to sidestep these issues, as part of platform.

However, Sen. Lyndon Johnson (with a consistent pro-oil and gas voting record) several times has defended percentage depletion during recent political tours.

Only definite stand Sen. John Kennedy has taken, outside of consistent anti-oil and gas voting record: Public statement that he supports National Fuels Policy Study—an issue that is strongly opposed by oil and gas industry, but apparently even more strongly supported by coal industry, i.e., recent full page ads in Washington, D. C. papers, New York Times and other publications.

Sticking to 1958-1959 voting record, Sen. Stuart Symington has publicly reaffirmed his belief that depletion percentage should be cut from 27½ to 15 percent.

Optimistic outlook for U.S. reserve-demand . . . Paul D. Torrey, chairman of Interstate Oil Compact Commission's Secondary Recovery and Pressure Maintenance Committee, reports nearly 90 billion barrels of crude oil can now be recovered with known methods—up 14.8 percent over 1958 estimates.

Big increase results from production made possible by new and improved recovery methods not included in 1958 estimate, i.e., thermal and solvent processes. Torrey reports conventional methods can recover 45.8 billion barrels of crude oil, up 2.1 billion barrels over 1958 estimate—new and improved methods can recover 44 billion barrels more, up 9.5 billion barrels over 1958.

U.S. will need all the crude oil reserves it can get, if recent U.S. Bureau of Mines prediction proves true. In just released encyclopedia on U.S. resources, Bureau forecasts U.S. oil demand will nearly double by 1975, from 9.1 million barrels per day in 1958 to 17 million barrels per day.

Khruschev to Cuba this month? . . . Predictions are that Premier Khruschev will attend Cuba's July 26 celebration. Reason: Timing would be perfect for propaganda barrage to offset national political conventions in U.S.

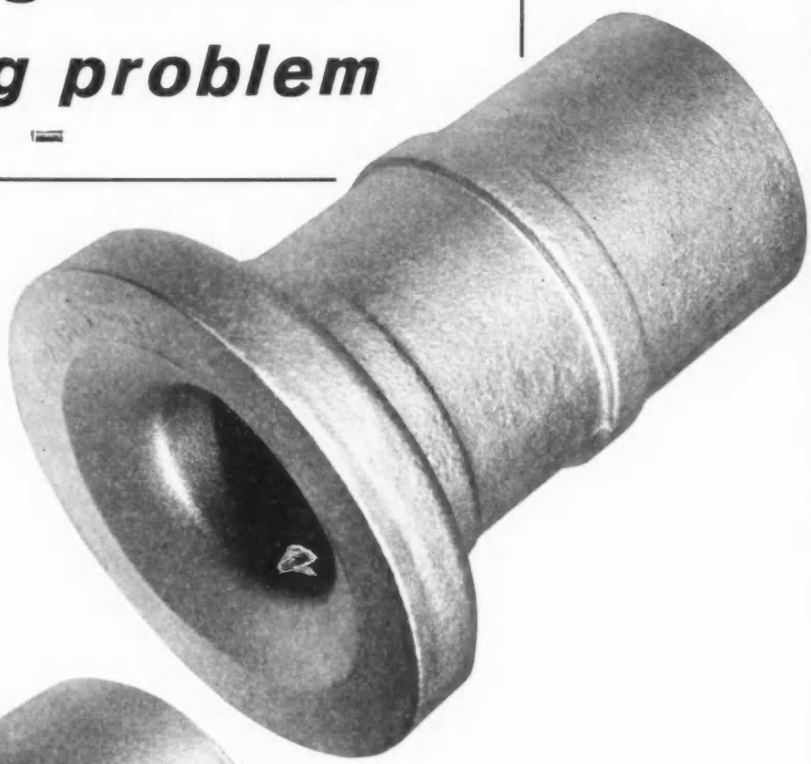
If "K" does bluster into Cuba in late July, he is expected to richly embellish Antonio Jiminez' Moscow announcement of Cuba's sugar-for-oil agreement with Russia. Under pact, Russia will provide up to 25 percent of Cuba's oil requirements, while saving Castro government about $24 million in foreign exchange. Premier also is expected to announce offer to provide Russian technicians should Cuba need help in refining Soviet oil.

Geophysical activity declines . . . Free World geophysical activity declined 8.9 percent to an average of 957 crews of all types operating during 1959. Eastern Hemisphere activity, which had been increasing steadily in recent years, dropped 14.5 percent. Western Hemisphere activity declined 5.1 percent.

According to annual Society of Exploration Geophysicists' report, recent downward trend in U.S. geophysical activity leveled off in 1959. Seismic work totaled 5,097 crew-months, up 33 crew-months over 1958. However, gravity meter and ground magnetic work declined, while aeromagnetic work was down nearly 47 percent, from 121,396 line-miles in 1958 to 64,639 line-miles last year.

The redesign of this forging solved a machining problem

BEFORE: Forged on an upsetter, this cylinder presented minor machining problems for the customer. The forging had to be trimmed on the sides; this resulted in flat spots, uneven cuts. It was also difficult to keep the OD concentric with the bore.



AFTER: Made on a mechanical press, this cylinder offers a better surface for machining. Sides don't have to be trimmed, so there are no flat spots, no uneven cuts to worry about. No gripping collar, either. Concentricity of OD and bore is excellent.

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In this case a mechanical press produced a better piece for the customer than an upsetter. But we know many cases where the opposite is true. One of the nice things about doing business with Bethlehem is knowing we'll recommend the one "right" method of manufacture the first time around. We have the experience, and the facilities (press, hammer, drop, and upsetter) to back up our recommendations. A chat with one of our design engineers costs you nothing . . . and may help to turn your problem into a profit. Our nearest sales office can arrange a meeting to suit you.

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Test your political IQ

Do YOU WANT increased federal control with its resulting higher taxes and tighter reins on your own economic and personal life?

Growing numbers of "big government" advocates do. They believe government must do the planning for the people. WORLD OIL believes in the opposite philosophy. The individual should have control over his government—should be able to make his own plans. An amalgamation of these plans, in keeping with the public welfare, should be the basis for government.

Despite arguments to the contrary, this philosophy can be kept alive. How? By informing yourself on issues affecting your economic and personal welfare—and doing something about them. Not just by voting, but by participating in politics on every level.

The first step in this direction is to check your own political IQ. The following Texas Mid-Continent Oil and Gas Association questionnaire will help you do just that. The questions are directed specifically in the area of petroleum, because you are a part of the oil and gas industry. See how you rate:

1. What county do you live in?_____ County.
2. Are you a registered voter for 1960? (Check one.) In some states this means, "Did you pay your poll tax?" Yes_____ No_____
3. Write the last name of the U.S. Congressman from your home district. _____
4. Write the names of three representatives in your state legislature.
   1. _____
   2. _____
   3. _____
5. What is the total state and federal tax per gallon of gasoline in your state?_____
6. What is the rate of state severance tax on production of crude oil in your state?_____
7. Have you written a personal letter to a member of Congress in the last year on

1. Fuels policy resolution?	_____Yes	_____No
2. Percentage depletion?	_____Yes	_____No
3. Gasoline taxation?	_____Yes	_____No
4. Natural gas regulation?	_____Yes	_____No
5. Labor legislation?	_____Yes	_____No
6. Any other subject?	_____Yes	_____No

8. Have you written a letter to a member of your state legislature about an oil or gas industry issue within the past year? _____Yes _____No
9. Do you belong to a civic club (such as Rotary, Lions, etc.)? _____Yes _____No
10. In Presidential elections, do you usually regard yourself as a_____Democrat, _____Republican, or_____Independent. (Check one.)
11. Have you ever worked as a campaign volunteer in behalf of any political party or candidate? _____Yes _____No
12. What kind of a job do you feel your employer does in keeping you informed on oil and gas industry affairs? _____Good _____Poor _____Fair
13. Generally, what attitude do you think the following persons have toward the oil and gas industry? (Check one.)

	Friendly	Unfriendly	Don't Know
Chet Huntley			
William Proxmire			
Lyndon Johnson			
Dwight Eisenhower			
David Brinkley			
Jerome K. Kuykendall			
Frank M. Porter			
Paul Douglas			
Drew Pearson			
Matthew V. Carson, Jr.			
Richard Nixon			
Douglas Edwards			
M. J. Rathbone			
Oren Harris			
Ralph Yarbrough			

14. Who would you say is the best known oil man in your city? _____
15. Have you made a speech before any sort of public gathering concerning the oil and gas industry within the past two years? _____Yes _____No
16. Do you recall reading or hearing of anyone in your company making a speech on an oil and gas industry subject during the past year? _____Yes _____No
    If "yes," who was the speaker?_____

According to Texas Mid-Continent, scores on the test were surprisingly low. If your rating falls into this category, particularly where major issues and voting records of potential candidates are concerned, take your June issue of WORLD OIL off the shelf and read "Oil and Gas in Politics," starting on Page 115.

Then get off your apathy and take an active part in politics during this presidential election year.

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From drawing board to well head installation, good, basic engineering design is built into every Gray Well Head Control Assembly component. Gray's Engineering standards require practical application of such engineering precepts as more strength, less weight; reduction of areas subject to pressure; elimination of unnecessary parts. Gray has done this, and combined it with flexibility to efficiently handle every well control problem in whatever pay zone you are working — deep or shallow, single or multiple.

For additional information about why Gray Engineering Design is another step forward in advanced quality control, write today for your copy of the new Gray Catalog.

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Better demand helps industry markets

Gasoline prices have been improving. But stocks remain higher than desirable. Demand for petroleum currently is strong. Crude oil production is strictly curtailed. Refinery runs are held down to combat surpluses.

THE INDUSTRY'S situation improved appreciably during the past month. Prices of gasoline were being generally marked up in the first half of June to more satisfactory levels, in evidence of better market conditions.

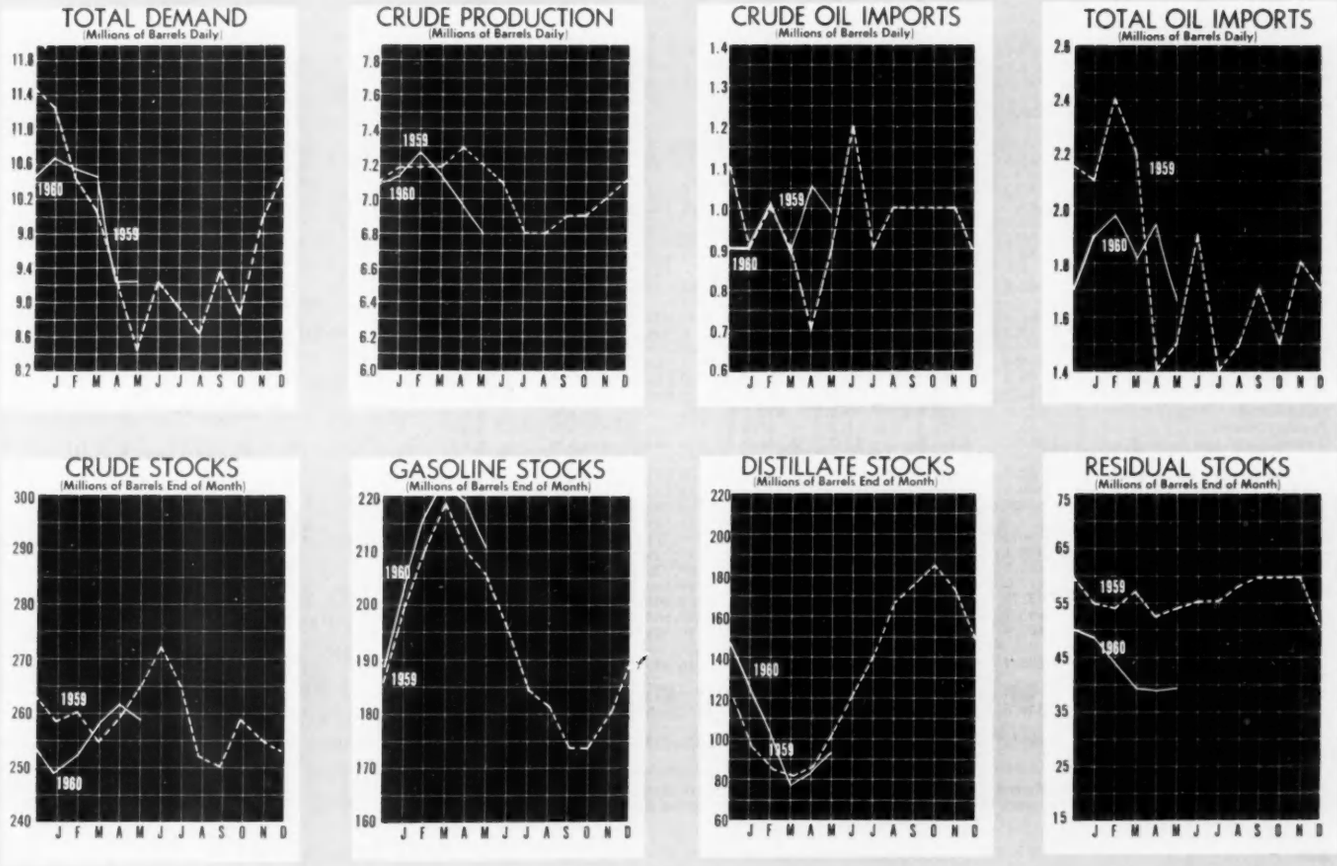
Remarkably good demand for petroleum products in May and early June was an important cause of market improvements. Continued strict control of crude production also helped, as did curtailment of refinery runs by numerous companies.

Demand. Total demand for all oils in May set a new all-time record for the month, 9.3 percent above May 1959. Virtually all products shared in the increase. The gains included those of 3.1 percent for gasoline, 10.5 percent for distillate fuel oil, 47 percent for kerosene, and 8.2 percent for residual fuel oil.

First five months. Aided by the sharp gains of May, petroleum demand for the first five months of 1960 showed better improvement over 1959 than that indicated for cumulatives through earlier months. Total demand for all oils in this year's first five months was 2.5 percent above the like period last year. An even better gain of 3.1 percent was made by the domestic component of demand, as exports were off 20 percent.

For the first five months, increases in demand for major products in-

Petroleum Trends...



U.S. Petroleum Demand and Supply (Thous. Bbls. Daily)

ITEM	MAY 1960	MAY 1959	% Diff.	April 1960	JANUARY-MAY 1960	JANUARY-MAY 1959	% Diff.
DEMAND							
All Oils, Total Demand	9,274	8,483	+ 9.3	9,249	10,183	9,932	+ 2.5
Domestic Demand	9,074	8,247	+10.0	9,049	9,982	9,681	+ 3.1
Export Demand	200	236	—15.3	200	201	251	—19.9
Gasoline, Total Demand	4,290	4,163	+ 3.1	4,251	3,976	3,935	+ 1.0
Distillate, Total Demand	1,376	1,245	+10.5	1,592	2,234	2,153	+ 3.8
Kerosine, Total Demand	191	130	+46.9	239	382	344	+11.0
Residual, Total Demand	1,386	1,281	+ 8.2	1,734	1,831	1,824	+ 0.4
Other Oils, Total Demand	2,031	1,664	+22.1	1,433	1,760	1,676	+ 5.0
CHANGE IN STOCKS							
All Oil, Change in Stocks	+132	+1,078		+613	—268	+ 64	
NEW SUPPLY							
Total New Supply	9,406	9,562	— 1.6	9,862	9,915	9,997	— 0.8
Domestic Production, Total	7,739	8,078	— 4.2	7,923	8,023	8,090	— 0.8
Crude Oil	6,809	7,219	— 5.7	6,998	7,080	7,216	— 1.9
Natural Gas Liquids	930	859	+ 8.3	925	943	874	+ 7.9
Imports, Total	1,667	1,483	+12.4	1,939	1,892	1,907	— 0.8
Refined Products	668	545	+22.6	856	898	996	— 9.8
Crude Oil, Total	999	938	+ 6.5	1,083	994	911	+ 9.1
Crude, East of California	691	769	—10.2	812	741	720	+ 2.9
CRUDE RUNS							
Crude Runs to Stills	7,930	7,896	+ 0.4	7,950	8,028	8,065	— 0.5
Domestic Crude	6,861	7,021	— 2.3	6,986	7,040	7,160	— 1.7
Foreign Crude	1,069	875	+22.2	964	988	905	+ 9.2

U.S Stocks of Oils (Million Bbls. at End of Month)

KIND OF OIL	TOTAL IN U.S. May 1960	TOTAL IN U.S. May 1959	% Diff.	TOTAL IN U.S. April 1960	EAST OF CALIFORNIA May 1960	EAST OF CALIFORNIA May 1959	% Diff.	EAST OF CALIFORNIA April 1960
All Oils	773.1	795.4	— 2.8	769.0				
Crude Oil	259.5	264.5	— 1.9	262.7	225.9	227.5	— 1.7	229.2
Gasoline	210.9	205.6	+ 2.6	219.3	178.8	175.3	+ 2.0	187.3
Distillate Fuel Oil	93.5	101.8	— 8.2	82.0	82.1	89.6	— 8.4	70.6
Kerosine	24.7	24.5	+ 0.8	20.4	22.9	24.1	— 5.0	19.1
Residual Fuel	39.9	54.0	—26.1	39.1	27.0	26.7	+ 1.1	25.5
Other Oils	144.6	145.0	— 0.3	145.5				

U.S. Crude Oil Production, by States (Thous. Bbls.)

STATE or DISTRICT	Daily Average for Month: May 1960	May 1959	% Diff.	April 1960	Total, January-May: 1960	1959	% Diff.
Alabama	18.6	14.6	+ 27.4	19.3	2,626	1,950	+ 34.7
Arkansas	80.6	80.3	+ 0.4	82.7	11,933	11,825	+ 0.9
California	835.5	847.3	— 1.4	827.8	126,178	127,355	— 0.9
Colorado	129.6	125.0	+ 3.7	128.6	19,529	19,109	+ 2.2
Florida	1.0	1.2	— 16.7	1.1	170	177	— 4.0
Illinois	212.1	207.3	+ 2.3	215.6	32,594	32,509	+ 0.3
Indiana	32.3	37.6	— 14.1	33.3	4,900	5,076	— 3.5
Kansas	303.9	319.5	— 4.9	312.9	46,737	50,376	— 7.2
Kentucky	63.1	85.1	— 25.9	61.6	9,247	10,967	— 15.7
Louisiana	1,036.0	968.7	+ 6.9	1,084.1	163,273	142,915	+ 14.2
North Louisiana	113.0	118.2	— 4.4	114.5	18,147	18,450	— 1.7
South Louisiana	923.0	850.5	+ 8.5	969.6	145,126	124,465	+ 16.6
Michigan	37.2	26.1	+ 42.5	34.2	5,402	3,947	+ 36.9
Mississippi	140.7	126.4	+ 11.3	134.3	21,407	18,549	+ 15.4
Mo.-So. Dak.-Tenn.	0.6	0.1	+500.0	0.7	107	15	+613.3
Montana	76.1	78.0	— 2.4	79.5	12,307	12,231	+ 0.6
Nebraska	59.9	67.2	— 10.9	62.0	9,445	9,020	+ 4.7
Nev.-Wash.-Alaska-Ariz.	0.9	0.2	+350.0	0.9	138	69	+100.0
New Mexico	302.6	287.8	+ 5.1	305.7	46,127	43,116	+ 7.0
Southeast New Mex.	265.3	247.7	+ 7.1	270.2	39,637	37,593	+ 5.4
Northwest New Mex.	37.3	40.1	— 7.0	35.5	6,490	5,523	+ 17.5
New York	4.9	5.1	— 3.9	5.1	757	808	— 6.3
North Dakota	59.3	46.9	+ 26.4	57.6	8,656	7,341	+ 17.9
Ohio	11.2	14.7	— 23.8	11.9	1,964	2,308	— 14.9
Oklahoma	518.5	547.6	— 5.3	532.7	82,245	84,650	— 2.9
Pennsylvania	16.7	16.5	+ 1.2	17.0	2,540	2,459	+ 3.3
Texas	2,417.1	2,867.8	— 15.7	2,541.0	398,209	434,528	— 8.4
Dist. 1: South Central	42.9	47.0	— 8.7	44.9	6,683	6,927	— 3.5
Dist. 2: Middle Gulf	106.1	128.8	— 17.6	117.9	18,112	19,158	— 5.5
Dist. 3: Upper Gulf	344.4	402.3	— 14.4	348.5	55,465	61,684	— 10.1
Dist. 4: Lower Gulf	176.5	201.2	— 12.3	190.8	29,349	30,948	— 5.2
Dist. 5: East Central	26.5	32.1	— 17.5	27.9	14,221	4,813	+195.5
Dist. 6: Northeast	228.1	283.6	— 19.6	246.5	38,736	43,391	— 10.7
Dist. 7-B: North Central	121.5	139.6	— 13.0	122.4	19,926	27,967	— 28.8
Dist. 7-C: West Central	117.0	138.3	— 15.4	122.9	19,165	20,929	— 8.4
Dist. 8: West	951.0	1,155.9	— 17.7	1,017.5	159,903	171,276	— 6.7
Dist. 9: North	195.1	208.7	— 6.5	193.7	29,565	31,536	— 6.3
Dist. 10: Panhandle	107.9	107.6	+ 0.3	108.2	16,541	16,200	+ 2.1
Utah	103.4	108.9	— 5.1	105.4	16,339	16,443	— 0.6
Virginia					2	3	— 33.3
West Virginia	6.3	5.6	+ 12.5	6.5	913	879	+ 3.9
Wyoming	340.5	334.0	+ 1.9	336.5	52,368	51,066	+ 2.5
Total, United States	6,808.6	7,219.5	— 5.7	6,998.0	1,076,113	1,089,691	— 1.3

Sources for above 3 tables: Bureau of Mines monthly reports, except last two months based on API and B. of M. weekly reports and WORLD OIL estimates, and all Texas districts from API.

cluded those of 1 percent for gasoline, 3.8 percent for distillate fuel oil, 11 percent for kerosine, and 4/10 of 1 percent for residual fuel oil.

Supply. Helping to improve the industry's situation again in May was continued strict curtailment of crude oil production, to a level 5.7 percent under May 1959. This made it possible for total new supply to be held 1.6 percent under May last year.

However, other segments of supply were above last year and partially canceled the benefit of stringent crude control. Production of natural gas liquids was up 8.3 percent. Total imports were up 12.4 percent, with crude oil receipts up 6.5 percent and product imports 22.6 percent higher.

Crude runs to stills were held at virtually the same levels in May as in April, averaging 7,930,000 barrels daily, as refiners generally held down throughput to combat surpluses.

Stocks. The net result of operations in May was the avoidance of a large buildup of stocks such as that of May last year. Stocks of all oils showed an increase of only 132,000 barrels daily, in favorable contrast with additions averaging 1,078,000 barrels per day in May of last year.

The fact that gasoline prices were advanced during the first half of June was some evidence that gasoline stocks are not seriously excessive. However, they are larger than desirable. It is true that gasoline demand currently is higher than ever before, and that fact helps to justify larger stocks than in the past. But even in relation to demand, gasoline inventories are greater than in other recent years except last year.

Gasoline stocks at the end of May 1960 were equivalent to 49.2 days' supply at the May rate of demand, compared with 49.4 days' supply in 1959, 47.7 in 1958, 47.3 in 1957, 45.6 in 1956, 44.1 in 1955, 51.3 in 1954, 44.5 in 1953, 37.8 in 1952, 40.0 in 1951, 41.1 in 1950.

Those figures indicate that gasoline stocks of 40 to 45 days' supply on May 31 would be adequate. Instead of the 211 million barrels held May 31, 1960, requirements were only 172 to 193 million, or 18 to 39 million less than were held. Averaging those extremes it may be said conservatively that gasoline stocks are too high by about 30 million barrels.

"Dog-eared" is a term sometimes applied to gravity and magnetics as exploration tools, but these "old guard" methods of exploration can teach many of us new tricks about getting certain prospects surveyed quickly, efficiently and economically.

A number of tails began wagging after explorationists stood up on their hind legs and took a new sniff at prospects via the gravity-magnetics route. If you are interested in cutting costs, while answering specific geologic questions, give us a whistle and we'll trot out our new Bulletin GM59-1, **"Gravity-Magnetics . . . what they *can* and *can't* do for the explorationist."**

GEOPHYSICAL SERVICE INC.
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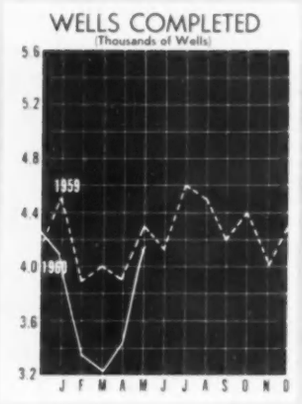
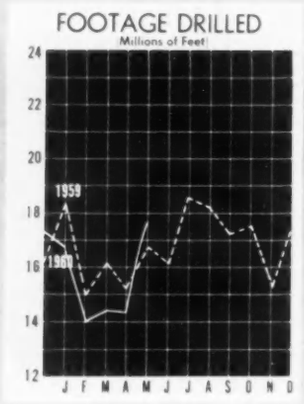
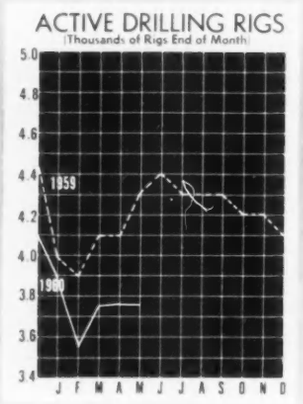
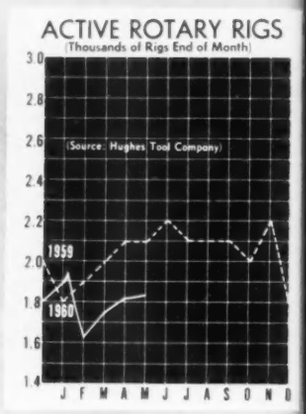
Drilling Activities.









Well completions take sharp upturn

AVERAGE DAILY well completions in May showed a marked increase over April. The average of 134 well completions per day was up 17.8 percent from April's 118 wells per day.

The May record was only 1.5 percent below the 136 wells per day completed during the same 1959 period. In contrast, April's average was down 7.3 percent from last year. March was down 15.5 percent.

States outside the major oil and gas areas have been keeping well completions from taking a landslide. During the first five months of this year, Michigan completion totals increased 48.5 percent over the same 1959 period, from 198 to 294 wells; Pennsylvania was up 39.1 percent, from 238 to 331 wells; Wyoming was up 34.2 percent, from 269 to 361 wells; Nebraska was up 31.3 percent, from 297 to 390 wells. Mississippi's total increased 21.8 percent, and Kansas 10 percent.

Rigs operating on May 31 increased 24 rigs over April 30 totals, to 3,752. However, the total was 533 rigs under the 4,285 reported operating on May 31, 1959.

Summary of U.S. Drilling Activity

ITEM	May 1960	April 1960	FIVE MONTHS JANUARY-MAY 1960	1959	% Diff.
New Wells Completed:					
Oil	2,032	1,737	9,022	10,370	—13.0
Distillate	72	59	354	344	+ 2.9
Gas	377	267	1,600	1,572	+ 1.8
Dry	1,587	1,396	7,254	7,338	— 1.2
Service	85	88	374	465	—19.6
Total New Wells	**4,153**	**3,547**	**18,604**	**20,089**	**— 7.4**
Footage Drilled (Millions of Feet)	**17.5**	**14.7**	**78.9**	**83.1**	**— 5.1**

Summary of U.S. Wildcat Drilling

ITEM	May 1960	April 1960	FIVE MONTHS JANUARY-MAY 1960	1959	% Diff.
New Field Discoveries:					
Oil	39	56	227	278	—18.4
Distillate	7	7	38	38	.....
Gas	29	20	103	103	.....
Total Discoveries	**75**	**83**	**368**	**419**	**—12.2**
Dry Wildcats	**701**	**618**	**3,311**	**3,389**	**— 2.3**
Total Wildcats	**776**	**701**	**3,679**	**3,808**	**— 3.4**
(Percent Productive)	9.7	11.8	10.0	11.0	.....
(Percent Dry)	90.3	88.2	90.0	89.0	.....

Use the Oil Bank of the Southwest to help you increase your returns from oil and gas activities. Every member of our Oil and Gas Department is experienced in both oil and banking. A large number of our directors and advisory committee are oilmen too! We understand the problems of the explorer, producer, researcher, refiner, transporter, wholesaler and retailer. It will be a pleasure to serve you.

Photo: Petroleum Engineers Frank E. McGonagill, Jr., (right), Vice President and Herbert F. Poyner, Jr., Assistant Vice President, inspect a gasoline plant, one of the major oil activities financed by Bank of the Southwest.

MEMBER F.D.I.C.

Bank of the Southwest
NATIONAL ASSOCIATION, HOUSTON

U.S. Drilling Activity in May and First Five Months, 1960-1959

STATE or DISTRICT	TOTAL NEW WELLS COMPLETED AND FOOTAGE DRILLED: DETAILS FOR MAY, 1960 — Oil	Dist.	Gas	Dry	Service Wells	TOTAL NEW WELLS — May 1960	April 1960	May 1959	Total Footage May 1960	DETAILS FOR JANUARY-MAY: NEW WELLS — 1960	1959	Percent Diff.	FOOTAGE — 1960	1959
Alabama	5					5	6	9	57,724	25	45	44.5	247,335	439,091
Alaska										3	4	25.0	34,288	49,305
Arizona				1		1			5,000	4	1	+300.0	12,700	2,000
Arkansas	25		3	24		52	53	52	192,140	238	317	— 24.9	876,721	1,031,238
California	77		9	38	1	125	111	140	624,978	547	585	— 6.5	2,565,145	2,787,129
Colorado	8		4	22		34	37	59	178,122	263	282	— 6.7	1,397,061	1,487,193
Illinois	55		3	99		157	137	174	318,318	766	783	— 2.2	1,566,110	1,743,913
Indiana	25		1	64		90	73	70	126,647	365	317	+ 15.1	491,699	528,299
Kansas†	241		24	211	20	496	391	403	1,719,395	2,078	1,889	+ 10.0	7,272,624	6,726,025
Kentucky	135		21	94	1	251	231	255	217,741	1,167	1,136	+ 2.7	984,350	1,051,450
Louisiana	185	22	35	136		378	203	280	3,083,437	1,317	1,460	— 9.8	10,998,397	11,489,135
North Louisiana	60		18	50		128	68	120	470,070	408	525	22.3	1,569,773	1,896,636
South Louisiana	125	22	17	86		250	135	160	2,613,367	909	935	2.8	9,428,624	9,592,499
*Gulf of Mexico	42	2	6	21		71	34	30	722,113	243	194	+ 25.3	2,498,697	1,936,811
Michigan	30		4	26	5	65	43	40	222,594	294	198	+ 48.5	1,005,857	582,738
Mississippi	21		2	28		51	62	50	556,051	313	257	+ 21.8	3,079,439	2,380,668
Missouri				1		1	3	1	3,000	6	3	+ 50.0	14,004	2,090
Montana	12		1	14		27	13	16	156,039	100	110	9.1	481,777	523,584
Nebraska	30			33		63	81	80	348,541	390	297	+ 31.3	2,255,018	1,761,130
New Mexico	85		30	27		142	124	172	714,392	725	682	+ 6.3	3,522,876	2,750,471
Southeast	72		3	23		98	94	89	519,131	495	385	+ 28.6	2,501,835	1,755,446
Northwest	13		27	4		44	30	83	195,261	230	297	— 22.6	1,018,041	995,025
New York	12		2	3	6	23	22	23	39,985	117	113	+ 3.5	201,380	194,335
North Dakota	9			15		24	23	52	145,232	124	183	— 32.3	773,354	1,120,527
Ohio	26		20	20		66	56	82	157,677	387	367	+ 5.4	971,260	1,001,801
Oklahoma	248	13	34	136	25	456	348	492	1,685,328	1,819	2,595	— 29.9	7,407,115	8,838,984
Pennsylvania	23		22	7	19	71	65	50	216,991	331	238	+ 39.1	974,621	787,691
South Dakota							2			14	6	+133.3	101,198	22,749
Tennessee				7		7	10	10	5,750	34	50	— 32.0	27,062	50,000
Texas	735	37	104	531	8	1,415	1,303	1,562	6,049,810	6,394	7,464	— 14.3	28,334,087	32,796,352
Dist. 1: South Central	39		1	40		80	103	93	246,941	426	430	— 0.9	1,211,278	1,070,025
Dist. 2: Middle Gulf	21	14	14	25		74	59	75	500,972	315	325	— 3.1	2,107,376	1,915,628
Dist. 3: Upper Gulf	40	6	8	50		104	103	120	704,135	488	491	— 0.6	3,514,320	3,617,768
*Gulf of Mexico				1		1	2	1	5,599	3	1	+200.0	24,703	11,005
Dist. 4: Lower Gulf-S.W.	22	11	22	45		100	79	137	558,241	432	553	— 21.9	2,444,326	3,000,578
*Gulf of Mexico														
Dist. 5: East Central		3		10		13	16	10	62,305	81	53	+ 52.8	379,579	290,914
Dist. 6: Northeast	43		3	28		74	67	59	413,392	330	321	+ 2.8	1,821,748	1,816,769
Dist. 7-B: North Central	115		22	106	3	246	193	204	631,824	976	1,023	— 4.6	2,900,956	3,251,607
Dist. 7-C: West Central	58	1	2	27		88	49	68	333,482	319	285	+ 11.9	1,319,147	1,199,193
Dist. 8: West	189		3	50	4	246	279	383	1,381,848	1,341	2,037	— 34.2	7,235,329	10,125,250
Dist. 9: North	164		9	130	1	304	269	328	792,671	1,223	1,486	— 17.7	3,256,407	4,303,623
Dist. 10: Panhandle	44	2	20	20		86	86	85	423,999	463	460	+ 0.7	2,143,621	2,204,997
Utah	10		2	5		17	18	22	93,788	91	131	— 30.5	498,002	751,822
Washington							1			2			12,082	
West Virginia	10		50	5		65	62	75	185,000	321	302	+ 6.3	877,991	768,811
Wyoming	25		5	40		70	67	51	360,963	361	269	+ 34.2	1,820,924	1,430,764
Others			1			1	2		6,865	8	5	+ 60.0	52,797	20,924
Total United States	2,032	72	377	1,587	85	4,153	3,547	4,221	17,471,508	18,604	20,089	— 7.4	78,857,574	83,120,249
Total Western Canada	85		15	33		133	82	218	735,254	939	1,009	— 6.9	5,376,372	5,128,806

WILDCAT DRILLING IN MAY AND FIRST FIVE MONTHS, 1960-1959: DETAILS FOR MAY, 1960 — Oil	Dist.	Gas	Dry	Total Wildcats	DETAILS FOR JANUARY-MAY — Oil	Dist.	Gas	Dry	TOTAL WILDCATS 1960	1959	DRILLING RIGS IN OPERATION (Rigging up, Drilling, Temp. Shut-Down): May 31, 1960	April 30, 1960	May 31, 1959
								2	2	9	5	7	14
					1			1	2	4	5	5	3
								4	4	1	8	10	12
			1	1	1	1	1	47	50	43	11	41	47
					4		3	108	115	104	123	122	152
1			1	27	29		4	118	130	156	54	51	66
			2	15	15		4	138	140	82	100	97	80
				49	49			251	255	183	286	264	239
				29	29			138	140	82	100	97	80
12				69	81	43		320	367	445	241	262	285
1				4	5	5		18	23	36	140	155	143
2	1	2	40	45	12	5	4	173	194	187	307	326	389
				21	21	3		1	63	67	54	75	61	71
2	1	2	19	24	9	5	3	110	127	133	232	265	318
		1	3	4		1	1	14	16	15	57	56	54
3		1	11	15	5		1	79	85	50	112	100	88
1			20	21	8			96	104	94	63	70	66
										1	3	2	1
			10	10	1		2	33	39	39	21	34	44
3			21	24	9		1	151	161	139	36	39	38
5		6	18	29	25		19	105	149	100	158	135	183
3		3	15	22	18		7	85	110	69	93	90	111
1		3	3	7	7		12	20	39	31	66	45	72
											25	25	25
			19	19	2			25	27	38	23	19	45
			5	5	2		3	15	20	8	156	166	213
4	2	7	10	53	19	4	19	159	201	350	395	405	494
		2		2			3	6	9	6	213	195	147
								5	5	4	1		2
			2	2	1		2	20	23	10	20	20	25
6	4	5	290	305	64	27	31	1,271	1,393	1,584	898	867	1,084
			29	29	2			123	125	129	32	24	42
	2		20	22	2	8	4	88	102	109	56	55	63
			27	27	3	7	2	108	120	112	112	93	95
								1	1	1	2	1	
1	2	2	30	35	5	9	9	130	153	174	65	56	87
			8	8	1	1	2	43	47	25	13	16	5
			16	16	3	2	1	61	67	66	69	65	57
2		1	63	66	20		7	284	311	330	81	68	103
1			22	23	5		3	83	91	91	75	77	78
2		1	28	31	20		2	147	169	243	194	194	287
			42	42	3			166	169	243	127	137	177
		1	5	6			1	38	39	62	74	82	90
1			5	6	1		2	35	38	34	32	30	43
								2	2				
											195	186	225
		1	30	32	7	1	4	122	134	97	86	93	121
								7	7	4	5	2	11
39	7	29	701	776	227	38	103	3,311	3,679	3,808	3,752	3,728	4,285
											151	134	191

*Gulf of Mexico wells are included in their respective district totals. †Kansas revised on basis of report from The University of Kansas, State Geological Survey.

Practical Operating Hints

These How-To-Do-It Ideas Can Save You Money

$10 is paid for each illustrated acceptable contribution. Mail to The Editor, WORLD OIL, P. O. Box 2608, Houston 1, Texas

Reach Engine Radiators With Steel Steps

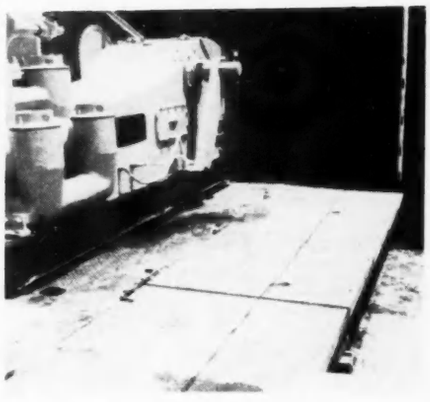
A handy means of getting to the top of the radiators was designed by using a 1½-inch pipe as the legs, ¾-inch rods as the steps framework and expanded steel as the actual steps.

The steps can be either welded to the rig floor or made detachable by adding sockets to the floor where the steps will be used.

Water From Gun Barrel Used to Cool Polish Rods

Here is a simple way to cool polish rods of pumping wells located adjacent to tank batteries. Install a section of 2-inch pipe, equipped with two needle valves, between the top and bottom packing holder on the wellhead. Connect the lower ¼-inch needle valve to any water source (in this case, the gun barrel) by small pipe or copper tubing.

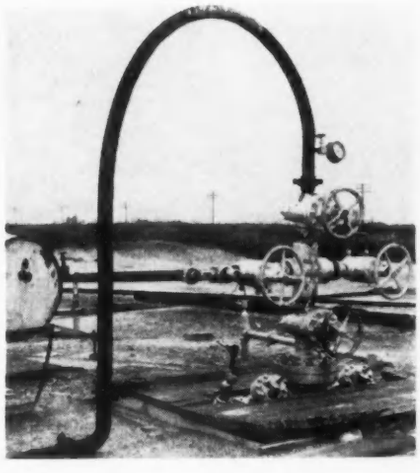
By cracking the upper needle valve and using it as a choke, water is allowed to circulate through the 2-inch nipple and around the polish rod. This cools the rod. The small quantity of water used is returned to a sump in the firewall where it is disposed of by evaporation.



Folded Platform Adds to Space at Mud Pump

Added walking space around the mud pump is increased through the use of a folded platform. When in transit, this walkway may be folded up, decreasing the load width.

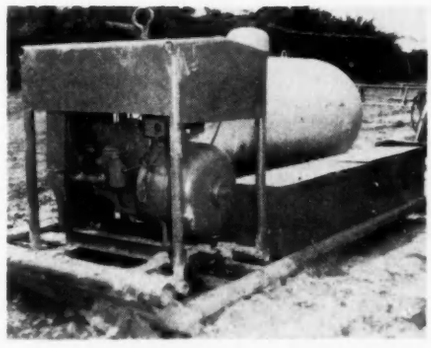
When rigging up the pump, these sides may be let down on some planking material which will support the platform on the outer edge. The walkway is pinned and if ever necessary, it can be completely removed from the joining pump skid.



Reduce Back Pressure On Gas Lift Wells

This operator has installed a direct flow line to the christmas tree in order to reduce the back pressure on the tubing of this gas lift well. Initially, the well was produced through the choke body on each wing of the tree. After placing the well on gas lift however, even large chokes produced excessive tubing back pressure and rendered very inefficient gas lift operation.

To overcome this obvious disadvantage, a joint of line pipe was bent and equipped with unions. Gas lift efficiency now is at a maximum since the direct connection between christmas tree and flow line subjects the well to a minimum of back pressure.



Consolidate Light Plant, Tool Box and Butane Tank

The light plant, its tool box and the butane tank are moved as one unit. All components are mounted on an 8-foot by 20-foot pipe frame for a skid base and the electric power unit is mounted on the front with its own skid base.

The butane tank is mounted on the back where the fuel lines are convenient to the engines and the rig floor. This leaves ample space for a tool box which runs nearly the entire length of the skids.

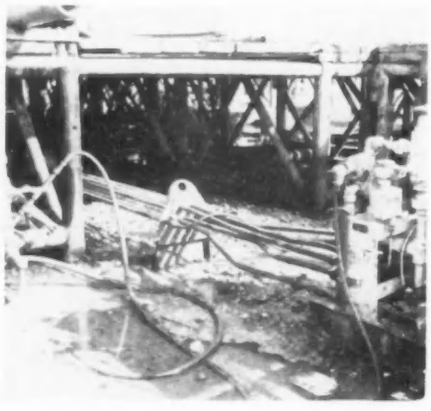
Bury the Valve to Prevent Freezing in Gas Regulator

One operator buried the valve beneath the ground and used residual ground heat to prevent freezing in regulators on high-pressure gas lines.

The valve shown is installed on a high-pressure gas line and provides a pressure drop of approximately 600 psi across the inner valve. Since the

gas is very wet, cold temperatures sometimes caused the inner valve to become frozen and inoperative.

The valves would never be buried to the extent that the packing gland or inner valve stem is below the ground surface. This method works well in areas which do not have extended periods of cold temperature.



Unitize Remote BOP Lines To Save Rigging-Up Time

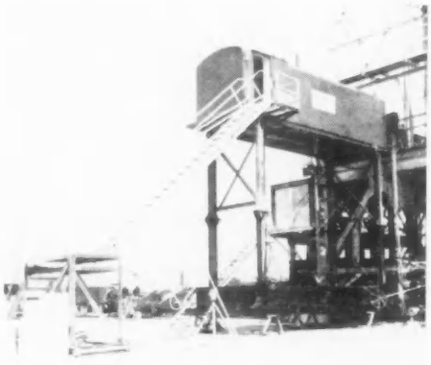
Every conceivable device is used around a rig to cut down on the time that it takes to rig up and tear down a rig. This is especially true when it comes to all of the pipe work that is necessary to put a rig to work. The remote blow out prevention controls are a case in point where the connection work is not only time consuming, but it has to be done right for safety sake.

One contractor has unitized the lines from the well head to the remote accumulator in such a manner that unions can be broken out at each end of the line and the whole center section can be picked up as a unit, placed on a truck, moved as a unit, and re-installed at the new location with the conections fitting exactly as they were at the last location. Bails are made a part of the brackets that hold the six pipes in place. They are bent slightly toward each other for ease in handling. This feature saves literally hours when rigging up in that it is not necessary to recut and rethread pipe to have the exact lengths that are needed.

Tag Keeps Meter Data Handy at Location Site

The tag shown attached to the orifice meter manifold contains all information required by field personnel to calculate the gas flow through the meter run. The card lists: (1) size orifice plate currently installed in the run, (2) coefficients for various plate sizes, (3) the orifice meter serial number and (4) date the orifice plate was last checked or changed.

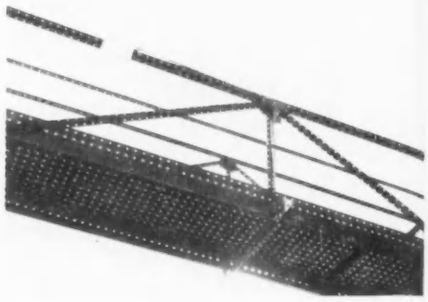
Since the information on the card is kept up to date, the pumper simply has to read the differential and static pressure valves on the chart and apply the correct coefficient to calculate gas production from the lease.



Mounted Doghouse Made Level With Derrick Floor

This doghouse is mounted at the same level as the derrick floor. Because of its height, the doghouse had to be supported with legs approaching the height of a 3-story building.

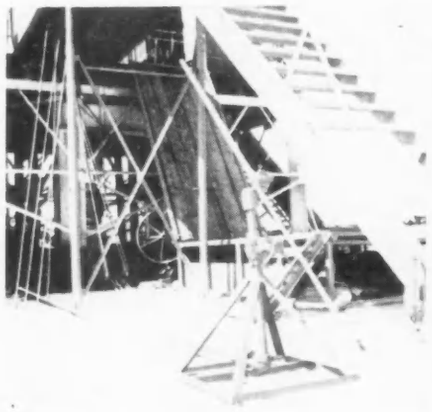
The two sets of legs at either end of the doghouse are hinged to fold up during a move. No structural braces are needed because X bracing is supplied by wire rope with turnbuckles.



Use a Metal Flag to Attract Pipe Line Gagers

Lease pumpers in West Texas normally are responsible for a number of leases and wells. Since it is a full day's job simply to make the rounds, the flag method has been developed as a time saver.

When a pumper "tops out" a tank and has it ready to sell to pipe line, he places the red metal flag on the elevated tank walkway in a vertical position. When the pipe line gager passes the battery he can tell immediately that a tank is ready to run. The gager then can put the tank on the line without the pumper being present each time.



Use Extra Mud Gun as Fire Fighting Equipment

An extra mud gun may be used to a piece of fire fighting equipment. This apparatus is conveniently located so that it may be directed at the master blowout preventer gate or at the origin of the fire.

The base of the unit is made of 1-inch angle iron and supports the

Drilling Contractors Cut Costs

Competition in the contract drilling industry was never keener. Drilling contractors must find new ways to lower their operating costs if they are to show a profit.

It is significant that many of the leading drilling contractors depend on equipment sold and serviced by Jones & Laughlin Supply Division. These leaders discovered long ago that lower first cost did not always mean lower final cost. They know they must use equipment that will give them more performance hours per dollar invested. This is why you'll find quality drilling equipment sold by Jones & Laughlin on the job for these industry leaders.

Backed by J&L service with field stocks of expendable supplies and replacement parts, these drilling contractors have cut their costs consistently.

Quality equipment and dependable service can lower *your* operating costs, give you the edge on competition. See your local J&L man today.

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If it's sold by J&L....
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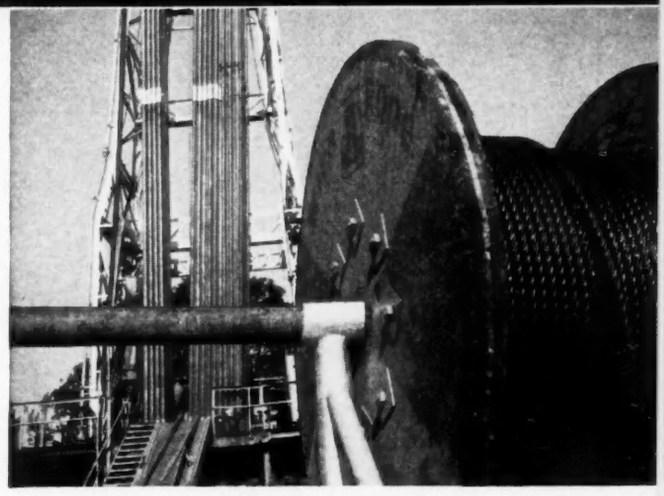
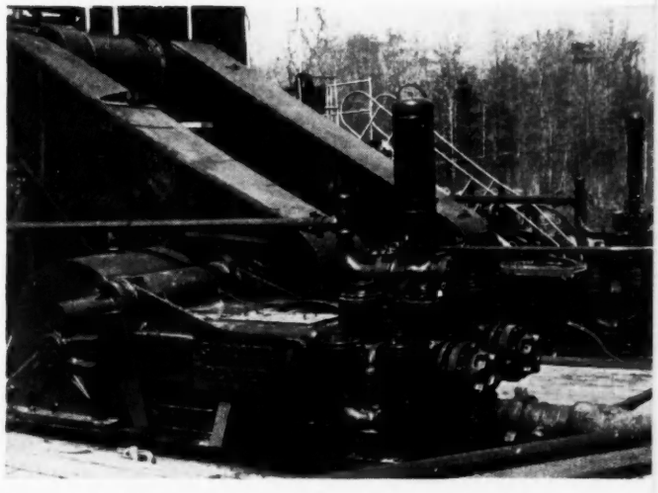


Because of unusual quality in materials and construction, J&L Wire Rope gives more ton miles. Result: Lower operating costs per foot of hole.



Three Gardner-Denver Mud Pumps on a well in Mississippi. Replacement of all Gardner-Denver parts can be made in the field, and these parts are as near as your J&L Supply store.

No tools needed to lay your temporary galvanized steel lines with McDowell "Fast-Line" Couplings. You save up to 80% installation time. Ask for illustrated booklet.

J&L's quality Blue Ribbon Drill Pipe is preferred by the drillers of the world's deepest wells. The J&L quality control program is the most exacting known. Ask your J&L Supply man for a beautifully illustrated 24-page booklet on oil country tubular goods.

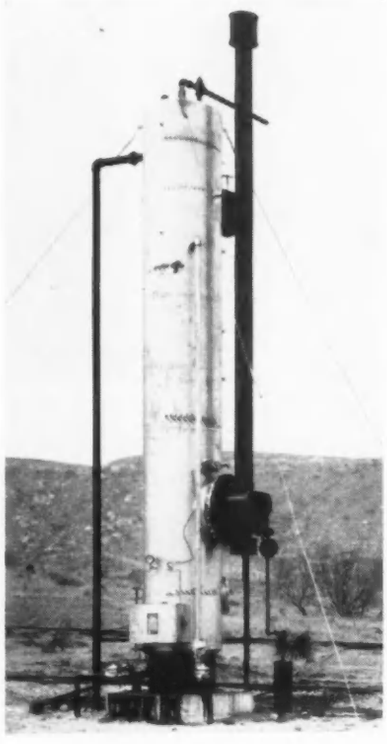
METROL®
Metering Treaters

METROL® Metering Treaters provide efficient separation of oil and water emulsions and accurately measure the oil and water in two integral metering chambers in the lower portion of the vessel.

Metering Treaters achieve greater economy by incorporating several functions into a single vessel. A Metering Treater will serve as an Oil and Gas Separator, a Free Water Knockout, an Emulsion Treater, and Oil and Water Meters. Thus, a Metering Treater can be used in place of several other separate pieces of equipment to obtain savings in equipment cost.

Free Water removal in the upper separating chamber on these Metering Treaters is an optional feature. Oil-Water Interface Control in these units is maintained by a Weir or by Float Operated Pilot and Valve.

METROL Metering Treaters are equipped with high capacity heating tubes that eliminate "hot-spots" and thus prevent fire tube failures. Also, these units are equipped with trouble-free and safe combustion control equipment to prevent "Blow-outs" and "Flashback."



METROL Model 36 MT-0020 VWK Metering Treater

Emulsions in most areas can be treated by these units without excelsior. However, excelsior can be furnished in these Metering Treaters in case it is needed or wanted.

METROL's design experience, combined with qualified field service, assures the producer of dependable and trouble-free operation.

METROL Metering Treaters are available in either vertical or horizontal type of construction, and in working pressures of 25, 50, and 100 psi.

If you have an Emulsion Treating problem where you wish to meter the oil and water, you will save money by using METROL Metering Treaters. Please write us for details.

SPECIFICATIONS AND CAPACITIES

Outside Diameter	Shell Length	Heating Capacity BTU/Hr	Working Pressure psi	Capacities
3'	20'—0"	200,000	25, 50, & 100	Settling and metering capacities for these units will be furnished upon request.
4'	20'—0"	400,000	25, 50, & 100	
6'	20'—0"	600,000	25, 50, & 100	
8'	22'—0"	1,200,000	25, and 50	
10'	22'—0"	1,800,000	25, and 50	

Every Unit is completely assembled, pressure tested, calibrated, and performance tested before shipment.

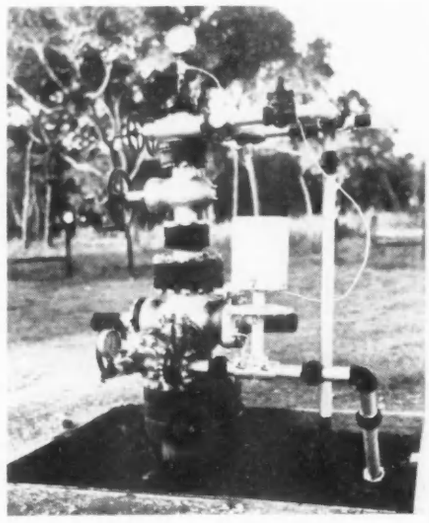
Competent Sales and Service Representatives located in all major producing areas.

*Pat. No. 2,818,738

OIL METERING and Processing EQUIPMENT CORP.
MELROSE 5-1226 • 4843 YALE STREET
HOUSTON 18, TEXAS

2-inch vertical piping. The vertical pipe is supported by the same size of angle iron designed in a pyramidal pattern.

A swivel joint is attached to the 2-inch piping material. A 1-inch piece of pipe is then attached to the swivel joint with a mud nozzle on the end which enables the deliverability of water to the fire at a high velocity.



Install Orifice Flange On Input Gas Line to Well

Here's an excellent way to hookup an orifice flange on an input gas line to a gas lift well. The flange is installed downstream of the intermitter and upstream of a choke nipple, which contains a relatively small choke, that has been screwed into the companion flange of the casing wing valve.

This allows relatively smooth gas flow through the orifice plate when the intermitter opens. The choke in the choke nipple can be changed whenever desired by removing the bull plug in the 2-inch tee. A portable meter is used to record charts.

Simple Mounting Operates Mud Pump Two Ways

By extending the V-belts from the rig floor to the mud pump, and extending the width of the mud pump sheave, the mud pump can be operated with an engine on the ground or from the rig floor or from both in case of emergency. When the hole is first started and mud pump pressures are low, the pump is powered from the compound on the floor. When the pressure increases, the engine on the ground can be placed into operation.

If it is necessary, because of depth

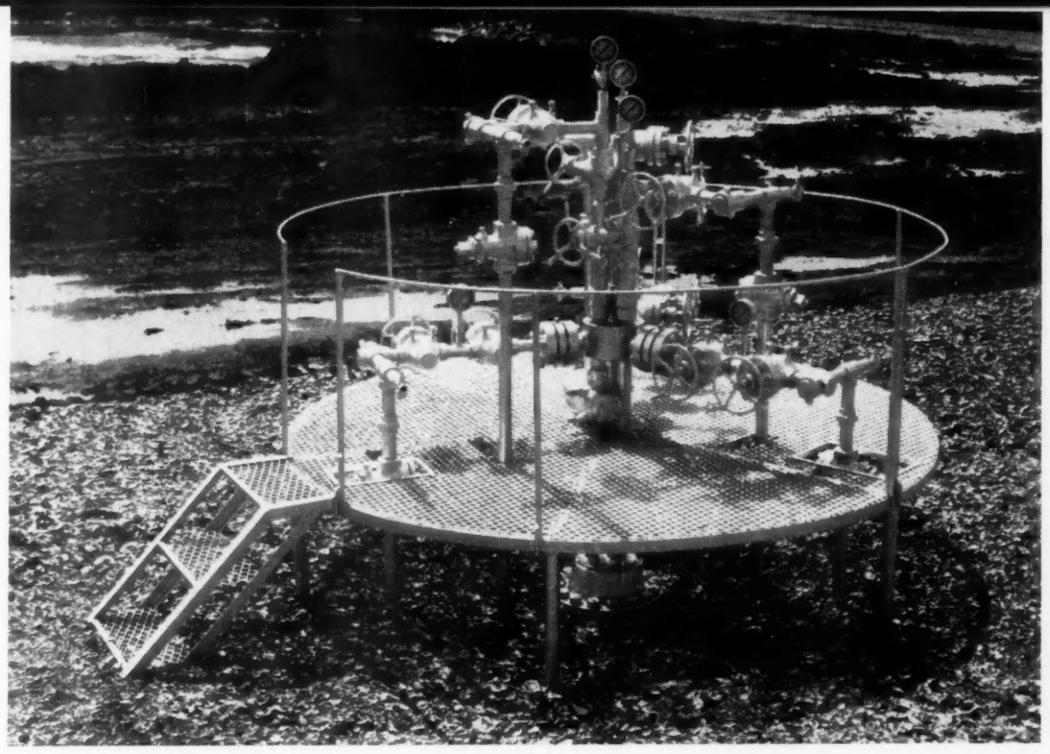


FIGURE 1—Sunray Mid-Continent Oil Company's J. A. Graves 6 is the first completion in the oil industry to produce simultaneously from six separate zones.

Sunray completes world's first sextuple well

Unique six-zone gas producer completed with three strings of 2⅞-inch casing, 1½-inch tubing for total cost of $78,000

By Paul E. Robinson, District Staff Engineer
Sunray Mid-Continent Oil Company, Corpus Christi, Texas
R. W. Scott, Engineering Editor, WORLD OIL

SUNRAY MID-CONTINENT OIL COMPANY has completed the oil industry's first small diameter sextuple well in North Laward field, Jackson County, Texas. The miniaturized well completion method was used to complete J. A. Graves 6 as a six-zone producer since known reserves of the six potential gas producing zones would not support the cost of drilling conventional-size wells. Total cost of the sextuple completion was $78,000. Figure 1 shows the completed well.

The unique installation consists of three strings of 2⅞-inch EUE tubing run as casing as in a conventional triple tubingless completion. However, two zones were perforated in each 2⅞-inch string, and 1½-inch integral joint tubing was installed and packed off between the perforated intervals (Figure 2). Thus each 2⅞-inch cased well produces as an "old style" dual completion—one zone flows through the 1½-inch tubing string and the other through the 1½—2⅞-inch annulus.

The sextuple completion of J. A. Graves 6 provided the economic answer to the problem of recovering gas reserves considered insufficient to warrant conventional development. Costs of conventional drilling and completion methods combined with the estimated low reserves had prevented past development, even though the sands were known to be productive.

All producing reservoirs are thin, shaley sands found between 4,700 and 6,650 feet. Most of the sands shale out within one or two locations, and vary in net thickness from 2 feet to 8 feet. Estimated reserves are very low.

Economics. A detailed economic analysis was made to determine the most feasible development program. Basic information considered included:

1. Very low reserves

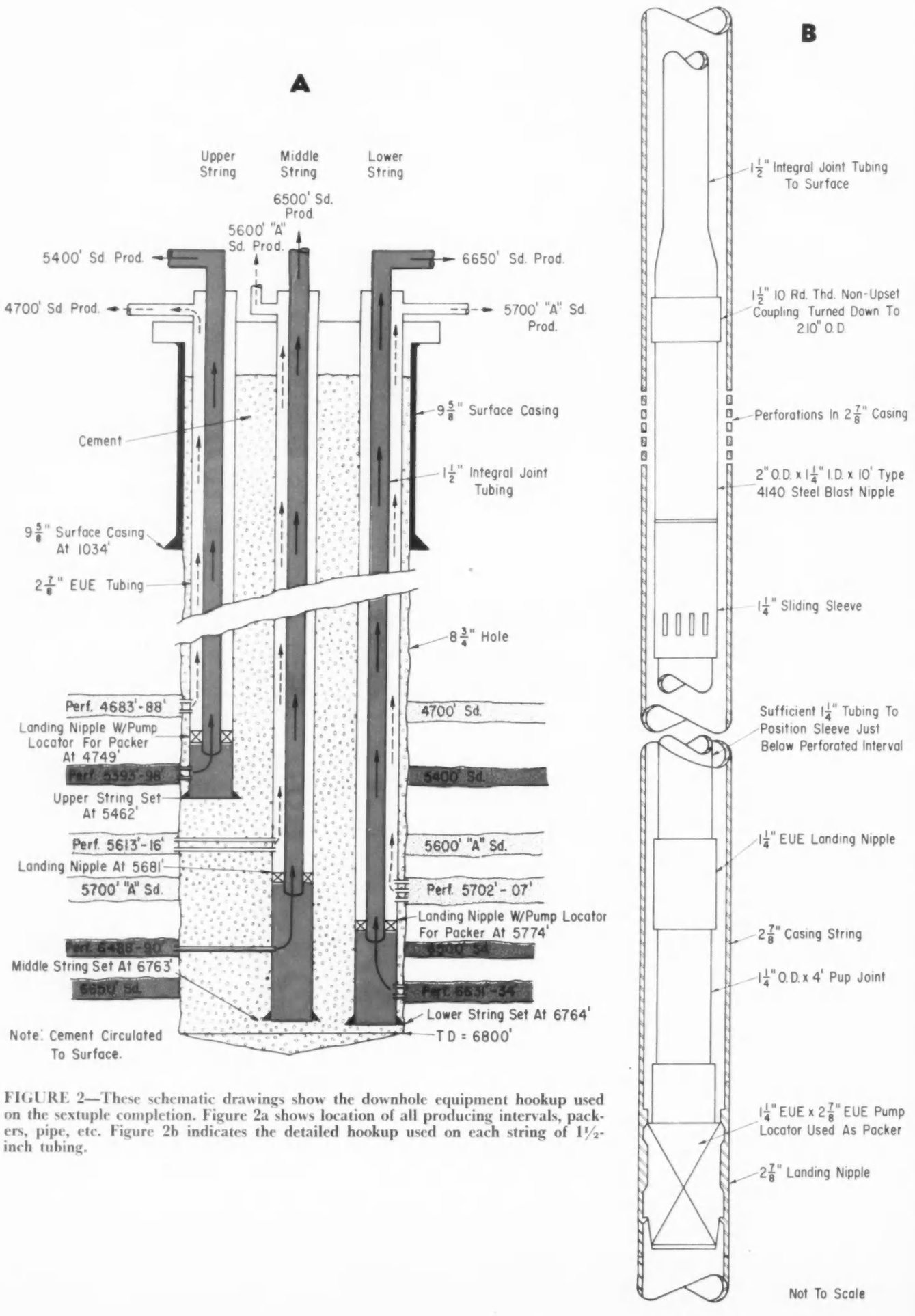


FIGURE 2—These schematic drawings show the downhole equipment hookup used on the sextuple completion. Figure 2a shows location of all producing intervals, packers, pipe, etc. Figure 2b indicates the detailed hookup used on each string of 1½-inch tubing.

FIGURE 3—Aluminum alloy guide shoes of this type were run on the bottom of each long string of 2⅞-inch casing. The short string of 2⅞-inch pipe was run bull plugged on bottom.

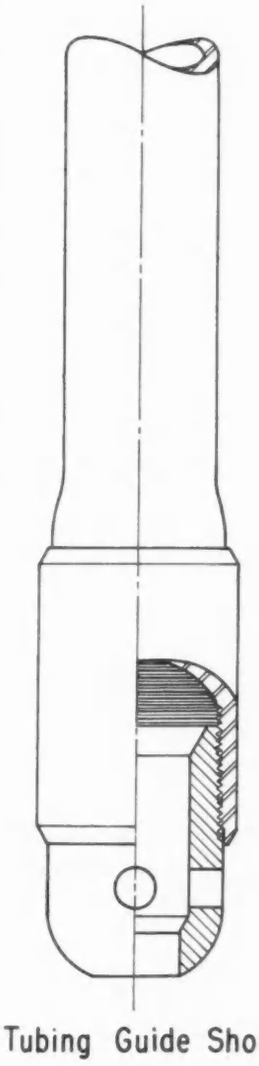
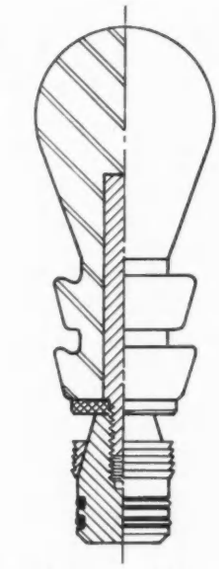


FIGURE 3



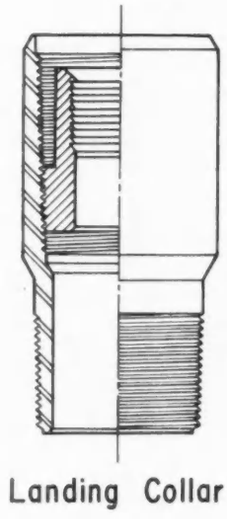


FIGURE 4—A latch type landing collar and ball type wiper plug were utilized to cement the sextuple completion. Latch collars were run one joint off bottom on the two long strings of 2⅞-inch casing.

FIGURE 4

FIGURE 5—Hard rubber tubingless completion type centralizers were used on each of the 2⅞-inch casing strings. The spiral design provides a full centralizing OD at all points on the circumference and helps prevent channeling of cement. Each unit is split so that it may be easily slipped on the tubing. Stainless steel bands are used at top and bottom to hold the centralizer in place.

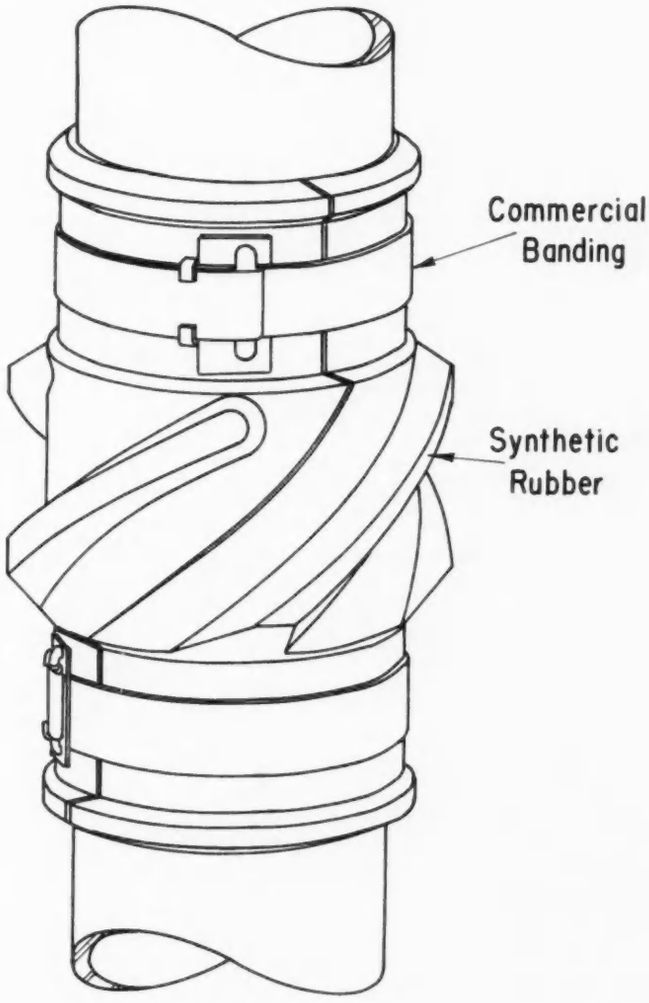


FIGURE 5

2. Wells would be produced at a low rate
3. Completions were needed in six zones to prevent drainage by offset operators.

Table 1 shows a cost comparison and economic evaluation of several different completion methods. The sextuple completion was decided upon primarily because of the attractive economics. Actual cost to drill and complete the sextuple well was $78,000. The estimated cost of two conventional cased-hole triple completions, to develop the same sands, is $145,000. Thus, savings realized on initial investment was $67,000 or 46 percent.

Drilling and completion methods used were patterned after the recently developed tubingless completion techniques advanced by a number of South Texas operators. Without the advice of these operators, completion of the sextuple well would have been much more difficult.

Drilling program. Surface casing consisting of 9⅝-inch OD 32.3 lb/ft pipe was run and cemented at a total depth of 1,034 feet using conventional methods. An 8¾-inch OD hole then was drilled to a total depth of 6,800 feet.

Native mud with a small amount of gel was used to drill from the surface to 4,000 feet. At this depth, mud was broken over to a 10.3 ppg gypsum-quebracho base mud. Viscosity was maintained at 35 to 40 seconds and water loss at five cc. No mud difficulties were experienced. The excellent cement job was due primarily to the good mud program.

A simultaneous induction electric log was run from total depth to surface. The completion zones and packer

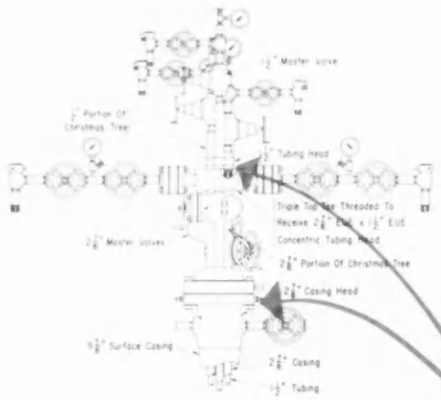
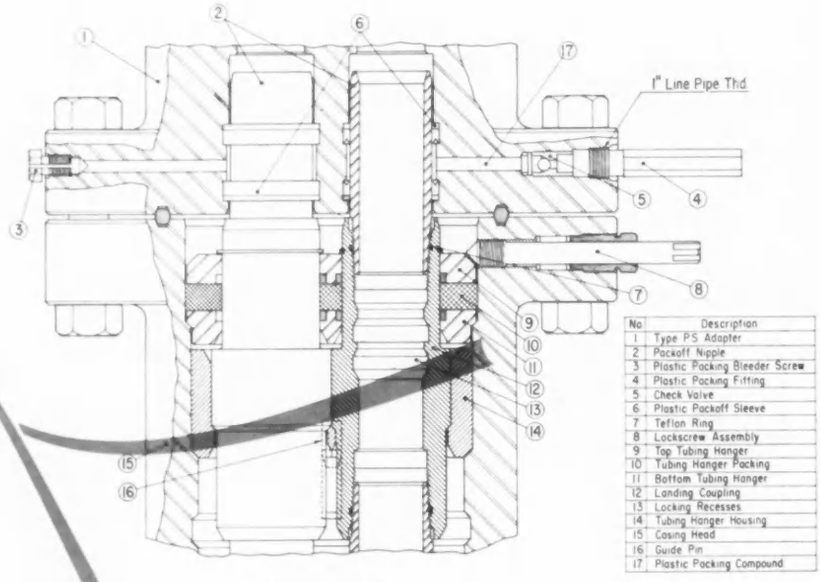


FIGURE 6

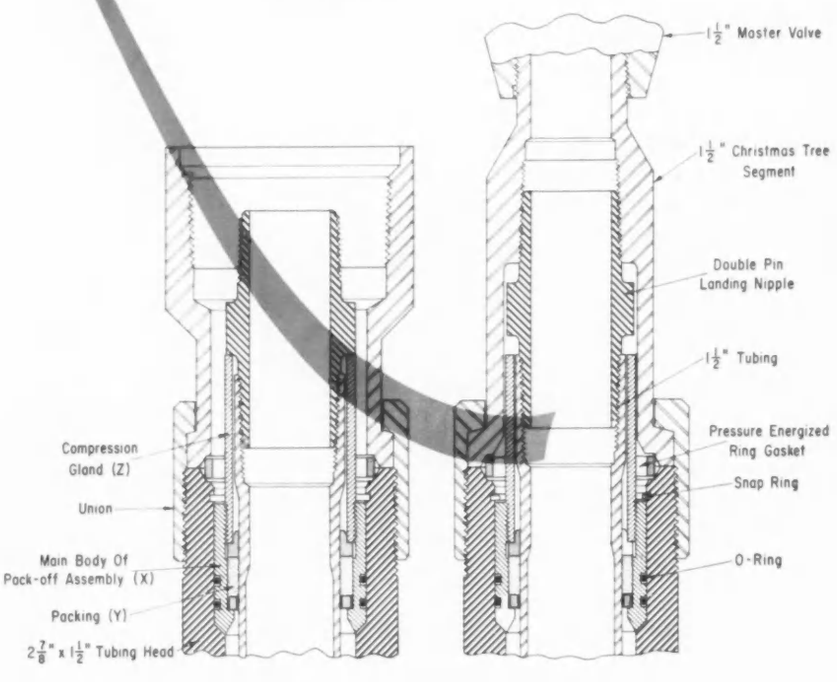


No.	Description
1	Type PS Adapter
2	Packoff Nipple
3	Plastic Packing Bleeder Screw
4	Plastic Packing Fitting
5	Check Valve
6	Plastic Packoff Sleeve
7	Teflon Ring
8	Lockscrew Assembly
9	Top Tubing Hanger
10	Tubing Hanger Packing
11	Bottom Tubing Hanger
12	Landing Coupling
13	Locking Recesses
14	Tubing Hanger Housing
15	Casing Head
16	Guide Pin
17	Plastic Packing Compound

FIGURE 7

FIGURE 6—Here is the complete wellhead hookup used on the sextuple completion. Note that the lower portion of the tree is bored 2⅞-inch EUE while the portion above the 2⅞-inch x 1½-inch tubing heads is 1½-inch EUE.

FIGURE 7—This engineering drawing shows details of the 9⅝-inch x triple 2⅞-inch casing head. All three strings of 2⅞-inch casing were suspended from mandrel type hangers as shown.



A FIGURE 8 B

FIGURE 8—Three of these special 2⅞-inch x 1½-inch tubing hanger assemblies were used on the sextuple completion. Figure 8a shows the 1½-inch tubing head equipped with a blowout preventer adapter. A ram type BOP was mounted on the adapter, and all 1½-inch pipe was run through the preventer. Figure 8b shows the 1½-inch portion of the Christmas tree made up on the 1½-inch hanger. It is of interest that these hangers were the only special equipment required for the entire completion. All other equipment was off-the-shelf stock.

location for each string of 2⅞-inch EUE tubing were determined from this log.

Running and cementing pipe. Three strings of 2⅞-inch OD 6.5 lb/ft EUE J-55 tubing, with the top of each collar beveled, were run independently as production casing. Two of the strings were run to near total depth or 6,764 feet. Both strings were equipped with a guide shoe on bottom and a latch collar one joint off bottom (Figures 3 and 4). The short string, with bottom bull plugged, was set at 5,462 feet. Landing nipples were installed approximately 60 feet below the upper completion zones of each string to serve as seats for 1½-inch production packers. Each string was centralized through all productive sands with hard rubber tubingless completion centralizers (Figure 5).

All three strings of 2⅞-inch casing were hung successfully on mandrels in the 9⅝-inch x triple 2⅞-inch casing head, which is shown in detail in Figure 7. It should be pointed out that the casing head also was constructed to receive a slip type 2⅞-inch casing hanger. For example, had trouble occurred in getting the third string of 2⅞-inch casing to bottom, the slip type hanger could have been substituted for the mandrel assembly and pipe could have been safely hung at any point.

Blowout preventers were removed and the 2⅞-inch portion of the triple christmas tree (section equipped with three 2⅞-inch master valves shown in Figure 6) was installed on top of the 9⅝-inch x triple 2⅞-inch casinghead. As indicated in Figure 6, this portion of the tree is equipped with a triple top tee connection threaded 2⅞-inch EUE. Cementing heads then were attached directly to the top tee con-

TABLE 1—Well Completion Cost Comparison

	Conventional Single Completion	Slim Hole Single Completion	Tubingless Single Completion	Conventional Dual Completion	Slim Hole Dual Completion	Tubingless Dual Completion	Conventional Triple Completion	Tubingless Triple Completion	Triple Tubing String Dual Completion Each String
Surface Casing	8⅝" O.D.	8⅝" O.D.	8⅝" O.D.	8⅝" O.D.	8⅝" O.D.	8⅝" O.D.	10¾" O.D.	9⅝" O.D.	9⅝" O.D.
Production Casing	5½" O.D.	4½" O.D.	2⅞" O.D.	5½" O.D.	4½" O.D.	2⅞" O.D.	7" O.D.	2⅞" O.D.	2⅞" O.D.
Tubing	2⅜" O.D.	2⅜" O.D.	.....	2⅜" O.D.	2⅜" O.D.	.....	2⅜" O.D.	.....	1½" O.D.
Intangible Cost									
Drilling	$17,000	$17,000	$17,000	$17,000	$17,000	$17,000	$17,000	$17,000	$17,000
Day Work	1,300	1,300	1,300	1,950	1,950	1,950	3,750	1,950	1,950
Cementing	1,250	1,250	1,250	1,250	1,250	1,250	2,400	2,400	2,400
Logging (I.E.S.,N.)	1,646	1,646	1,646	1,646	1,646	1,900	1,646	2,400	2,400
Coring (S.W.C.)	900	900	900	900	900	900	900	900	900
Perforating	400	400	450	650	650	1,302	890	1,590	1,984
Casing Supplies	767	737	673	767	737	1,103	925	1,100	1,250
Drilling Mud	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Special Completion Rig	.....	.....	.....	.....	.....	.....	.....	750	1,500
Contigencies	2,800	2,800	2,800	2,900	2,900	3,000	3,200	3,300	3,500
Total Intangibles	$28,063	$28,033	$28,019	$29,066	$29,033	$30,405	$32,700	$33,400	$34,894
Tangible									
Surface Casing	$ 2,823	$ 2,823	$ 2,823	$2,823	$ 2,823	$ 2,823	$ 3,735	$ 3,660	$ 3,660
Production Casing	13,124	8,025	6,120	13,124	8,025	12,240	18,088	18,360	18,360
Tubing	4,624	4,624	.....	4,624	4,624	.....	9,250	.....	10,000
Wellhead	1,600	1,500	1,200	2,100	2,100	1,600	5,700	5,000	6,000
Subsurface	550	550	.....	900	900	.....	3,200	.....	2,400
Total Tangibles	$22,621	$17,522	$10,143	$23,571	$18,472	$16,663	$39,973	$27,020	$40,420
TOTAL COST	$50,684	$45,555	$38,162	$52,637	$47,505	$47,068	$72,673	$60,420	$75,314
No. of Wells Needed	6	6	6	3	3	3	2	2	1
Total Cost of Development	$304,104	$273,330	$228,972	$157,911	$142,515	$141,204	$145,346	$120,840	$ 75,314
Profit to Investment Ratio	0.15	0.30	0.55	1.25	1.49	1.50	1.45	1.94	3.71

nections of the two long strings of 2⅞-inch casing.

The well was cemented down both long strings of 2⅞-inch casing with 1,175 sacks of regular cement containing 12 percent gel and 5/10 pound retarder per sack. Twenty-five barrels of salt water were pumped down each string ahead of the cement slurry.

Tubing wiper latch-in plugs (Figure 4) were displaced simultaneously down both long strings with salt water, and bumped with approximately 2,500 psi. The 2⅞-inch tree master valves were closed and a surface pressure of 2,000 psi was maintained for ten hours. Clean cement returns were obtained while pumping the plugs down. The drilling rig was released immediately after plugs were bumped.

Completion procedure. After cement had set, neutron collar locator logs were run and both zones of each 2⅞-inch casing string were perforated with an oriented gun (Figure 9). Figure 10 shows orientation curves obtained when one zone of the sextuple was perforated. The polar plot indicates positions of the adjacent 2⅞-inch casing strings. A workover unit then was rigged up to run the three strings of 1½-inch integral joint tubing.

As mentioned previously, the top tee of the 2⅞-inch portion of the triple tree was provided with triple 2⅞-inch EUE top connections. Prior to running 1½-inch tubing, a 2⅞-inch x 1½-inch tubing head (Figure 8) was made up in each bore of the triple top tee.

One of the 1½-inch tubing head segments then was equipped with a blowout preventer adapter as shown in Figure 8a, and a 1½-inch ram type blowout preventer was attached to the female connection on top of the adapter. The 2⅞-inch master valves on the remaining two strings were closed for well control.

The 1½-inch tubing then was started in the hole, with each string equipped as follows:

A pump locator (Figure 11) was run on bottom. The locator seats in the 2⅞-inch EUE landing nipple and serves as a pack-off or production packer between the two perforated zones. A 1¼-inch EUE landing nipple and circulating sleeve (Figure 12) separated by 1¼-inch EUE tubing, then were placed in the string. One 2-inch OD x 1¼-inch ID type 4140 carbon steel blast nipple was positioned opposite upper perforations. The remainder of each small tubing string was composed of 1½-inch 2.4 lb/ft J-55 integral joint tubing.

The last joint of 1½-inch tubing to be run was left extending above the 1½-inch tubing head. Referring to Figure 8, the main body of the tubing hanger pack-off assembly (x) then was stripped over the pipe. Packing (y) was wrapped around the pipe and inserted in the recess of the main pack-off body (x). Compression gland (z) was screwed into the top of item (x) and the packing was compressed to effect a seal between the inner portion of the main body of the pack-off unit (x) and the 1½-inch tubing.

A special double pin landing nipple (Figure 8) then was made up in the box connection of the last joint of 1½-inch pipe. A landing joint was made up to the upper pin connection of the double pin landing nipple. The entire assembly, last joint of 1½-inch tubing, entire pack-off assembly (x, y, z) and double pin landing nipple, then was lowered through the blowout preventer and seated in the 1½-inch tubing head. At this point, the weight of the 1½-inch string was transmitted to the 1½-inch tubing head and 2⅞-inch casing head through the double pin landing nipple which rested on the compression gland element of the pack-off assembly (Figure 8a). The blowout preventer and blowout preventer adapter were removed from the 1½-inch head.

A snap ring (see Figure 8) was inserted to retain the pack-off assembly in the head. Next, the pressure energized ring gasket was seated in the top of the tubing head.

The 1½-inch tubing string with double pin landing nipple attached then was picked up by stripping through the pack-off assembly.

The 1½-inch christmas tree segment then was screwed to the 1½-

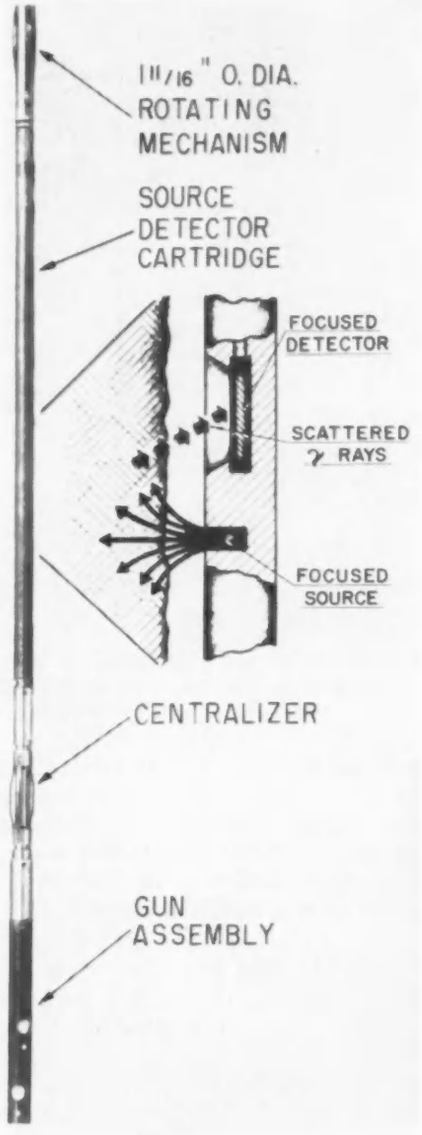


FIGURE 9—A single line radiation orienting device and perforator assembly was used to perforate the three strings of the sextuple well. The orienting instrument "sees" the adjacent pipe strings through its response to density changes in the material surrounding the tool.

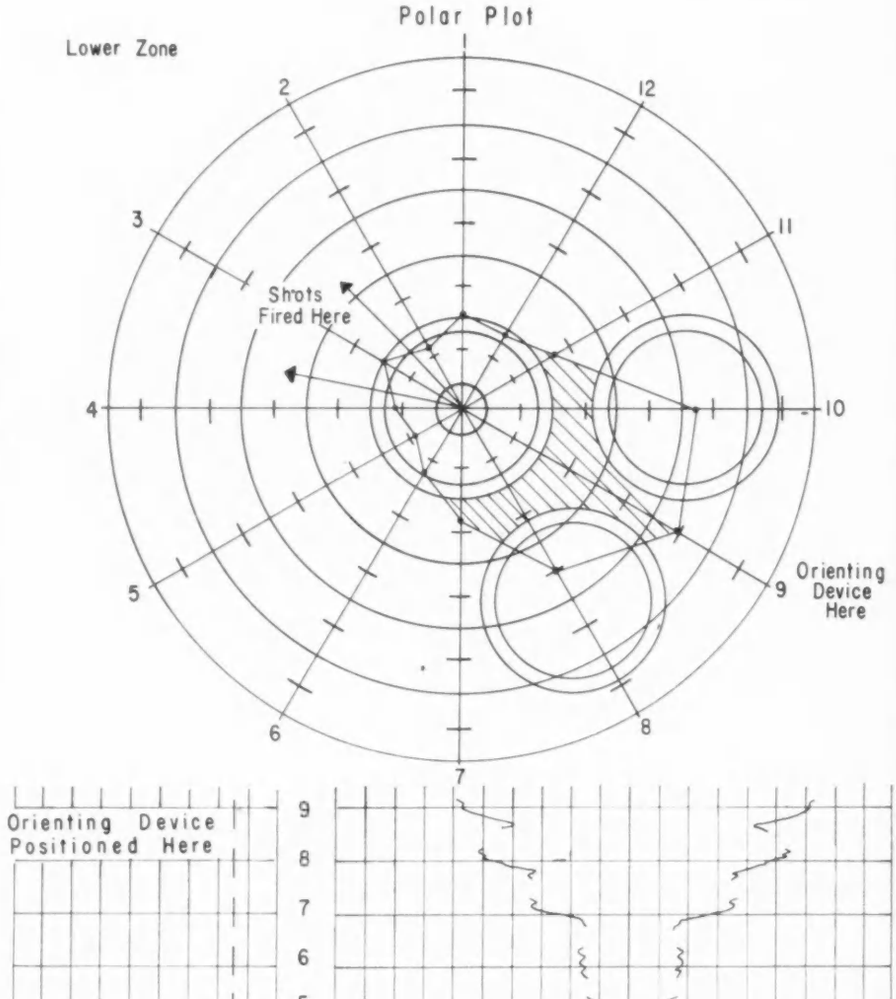


FIGURE 10—These orientation curves were obtained when one zone of the sextuple was perforated. The polar plot (top) of radiation levels obtained as the gun was rotated indicates the relative positions of the adjacent casing strings.

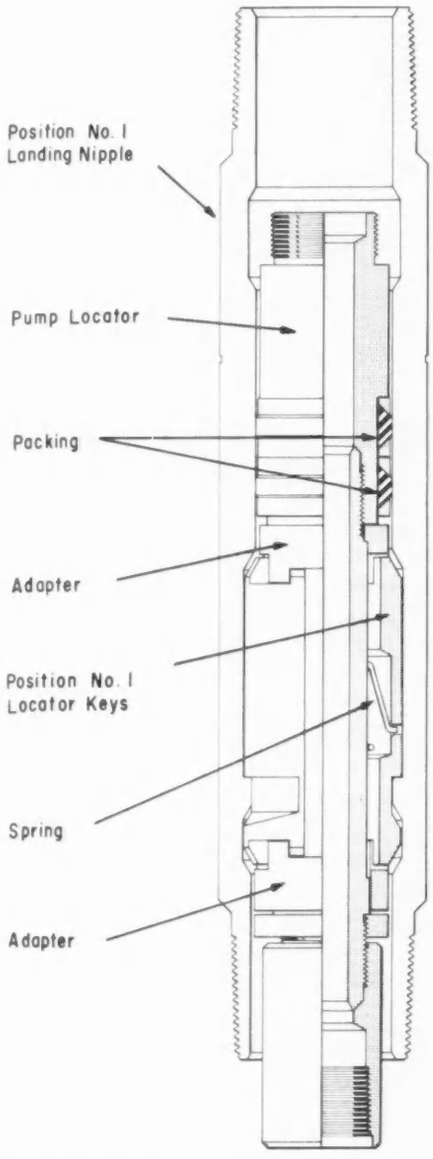


FIGURE 11—A pump locator was run on the bottom of each 1½-inch tubing string and seated in a properly positioned landing nipple previously run in the 2⅞-inch casing string. The locator serves as a production packer and effectively separates the two producing zones in each 2⅞-inch casing string. This cutaway drawing shows how the locator is seated in the landing nipple. Approximately 4,000 pounds tubing weight was set on the locators used in the sextuple completion, and all were tested satisfactorily.

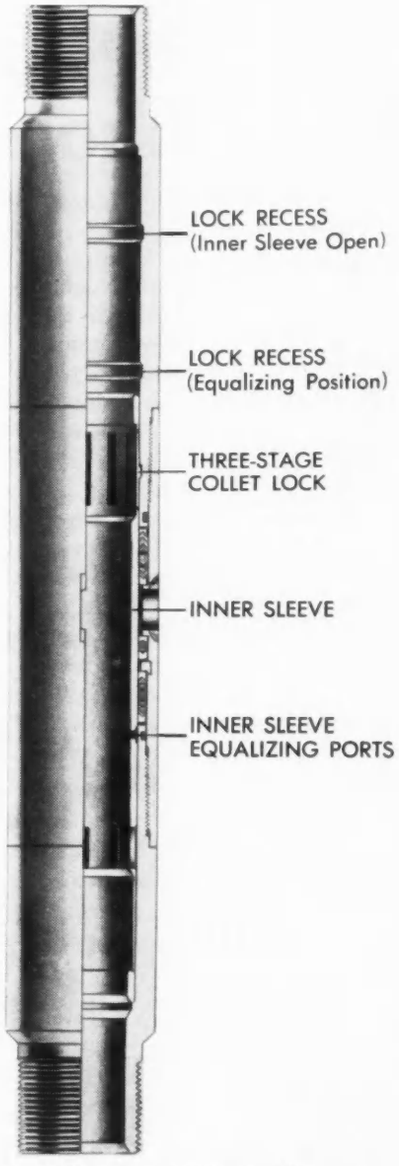


FIGURE 12—A 1¼-inch sliding sleeve of this type was run in the closed position on each string of 1½-inch production tubing, and positioned immediately below the uppermost perforations. All sleeves were opened and closed by wireline.

inch double pin landing nipple (Figure 8b), and the complete assembly was lowered until it seated on the tubing head. At this point, the weight of the 1½-inch string was transmitted upward through the double pin landing nipple to the christmas tree adapter and finally to the top of the 2⅞-inch casing head (Figure 8b). The union was made up to complete the job.

This procedure then was repeated for the other strings of 1½-inch tubing. After each string of 1½-inch pipe was run, the 1½-inch master valve was closed for well control.

The workover unit was released after all 1½-inch tubing was landed and the upper half of the tree was completely installed. All circulating sleeves were opened by wire line and a swabbing unit was used to make two pulls from 500 feet in one string to establish flow. The swabbing unit then was released.

The remaining wells were rocked in with gas from the well that had been swabbed. All wells were cleaned to the pit, circulating sleeves were closed and each zone was potentialed. Packers leakage tests then were run successfully on all three strings. Table 2 relates well designations, perforations and calculated absolute open flow potentials.

TABLE 2—Well Tests, J. A. Graves Well

Well Designation	Perforations	Absolute Open Flow Potential
Graves No. 6 LT....	6631′–34′	54,000 Mcfd
Graves No. 6 LC....	5702′–07′	600 Mcfd
Graves No. 6 MT....	6488′–90′	660 Mcfd
Graves No. 6 MC....	5613′–16′	1,480 Mcfd
Graves No. 6 UT....	5393′–98′	10,500 Mcfd
Graves No. 6 UC....	4683′–88′	7,000 Mcfd

Key: T—Tubing
C—Casing
L—Lower
M—Middle
U—Upper

The true significance of the sextuple completion is the fact that the only special equipment required was the upper half of the christmas tree. All other equipment is readily available and familiar to field personnel. It is possible and perhaps probable that eight completions can be as easily obtained as six, if sands are present and the economic and physical conditions should warrant. In fact this may be considered one method of combating the present economic squeeze in the oil industry. —**The End**

About the Author

Paul E. Robinson is a district staff engineer in Sunray Mid-Continent Oil Company's Corpus Christi, Texas district, Production Department. He has worked in several of Sunray's districts since joining that company in 1956. Previous employment includes two years with Stanolind Oil and Gas Company in Pampa, Texas, and two years with Coynco Inc. in Tulsa. He was graduated from the University of Tulsa in 1952 with a B.S. degree in petroleum engineering.

Louisiana operators ask—Why drill for offshore oil?

State multiple completion ruling curbs development drilling for offshore oil reserves

By Don E. Lambert,
Associate Editor, WORLD OIL

UNTIL LAST MONTH, Louisiana exploration and drilling activity was moving along at an unspectacular pace. Outside of the $246 million offshore lease sale in February and Sinclair's quintuple completion 40 miles off the Louisiana coast in April, few headlines were being made.

The future was looking a little brighter, particularly for offshore operations. Five wildcats and 58 development wells were drilling on June 1. Plans were on the books to purchase at least $50 million worth of offshore drilling equipment in the next two years.

Why Louisiana is concerned about crude oil production . . .

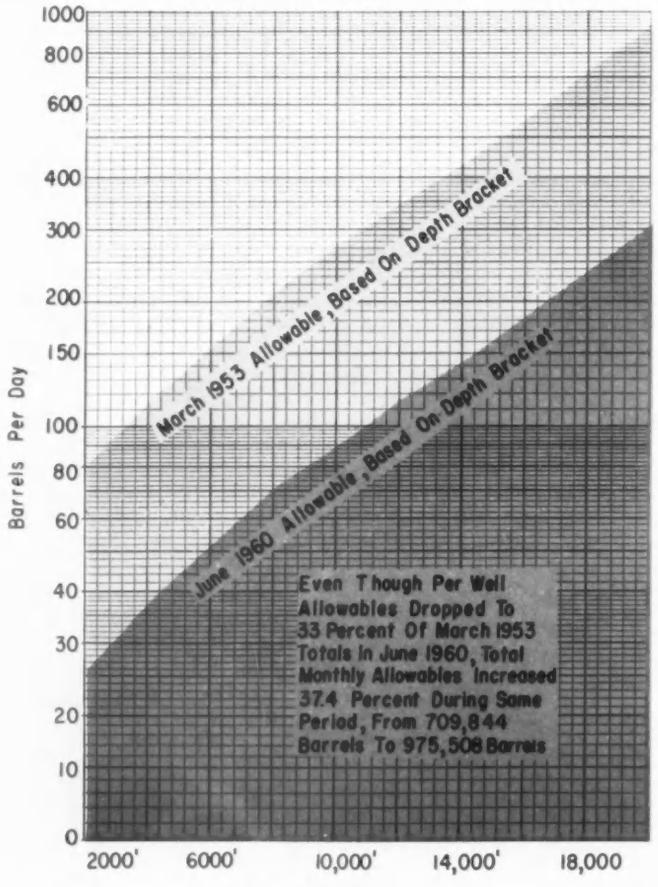


FIGURE 1

It appeared that more than two decades of expensive technological improvements were beginning to pay off, both for offshore and onshore operators. This technical breakthrough was badly needed, for soaring offshore drilling costs were making it economically impractical to make single completions.

Some operators were predicting, perhaps optimistically, that their income might finally come close to covering expenses by the end of the year. This balancing of the books has long been overdue. Estimates are that at least $3 billion have been invested in offshore operations, while revenue received has totaled little more than $600 million.

Now operators are wondering how far beyond 1960 it will be before they start breaking even. Reason: Late in June, Louisiana's Conservation Commissioner Ashton Mouton issued a temporary written order retroactive to June 7, which said in effect:

1. Allowables will be granted for multiple completed oil zones that are completed in existing wells within the same fault block. However, any new zones will not be allowed to produce unless they are completed singly.
2. When a gas well is completed with one or more oil sands, which has not previously been approved, only one oil sand will receive an allowable.
3. Operators may continue to obtain multiple completion work permits, even though they cannot receive allowables until the temporary order is rescinded.
4. Multiple gas completions will not be affected by the order.

Why the order was issued. According to Thomas M. Winfiele, chief engineer for the Louisiana Conservation Department, "The purpose of this limitation is to temporarily minimize the number of oil well completions during this time of short market, and one of the ways of doing this is to not allow any new pools to be multiple completed with any other pools."

It was pointed out that under the present system, based on depth bracket, allowables were cut in May and June to 33 percent of the March 1953 figures. In short, an 8,000-foot well that was allowed to produce 214 barrels of crude per day in March 1953 was allowed 71 barrels per day last month. (See Figure 1).

The fear was expressed that further allowable reductions would cut the return on investment to the extent that operators would be discouraged from coming to Louisiana to drill. No mention was made of the new formula proposed by several operators which would set up an allowable pattern based on acreage in addition to depth bracket. Those opposed to the plan, which would provide higher allowables for increased well spacing, argued that it would discourage development of some fields and would hurt onshore operators while it helped offshore operators.

Blow to offshore operations. The Louisiana Conservation Department reports that four new fields were discovered offshore during 1959, all gas—and that 358 wells were multiple completed from January through May of this year.

Of the 358 total, 29 offshore and 77 onshore oil wells were multiple completed in new fault blocks—29.6 percent of the total. The remaining 252 wells were development or gas completions.

Thus, at the previous completion rate, less than one-third of 1960 multiple oil well completions will be affected by the ruling. And by far the smallest share of that percentage will be drilled offshore.

However, it is generally known that a much higher percentage of oil wells completed offshore are multiple, compared with onshore. It is the only way offshore operations can be made economically practical.

Effect of ruling. One thing is certain, the recent trend toward increased offshore oil field development will slow to a crawl. Other reactions include:

- Exploratory drilling will continue to be reasonably aggressive. Term contracts (6-12 months) have been signed for at least one-third of the estimated 47 mobile marine drilling platforms now operating offshore. Also, offshore leases stipulate that to hold each 5,000-acre block, operators must drill at least one well or have operations in that block before the five-year expiration dates.
- Exploratory drilling may increase in the offshore gas area from Eugene Island west to the Louisiana line. However, only one-third of the offshore gas fields are now hooked up to pipe lines—so this will have to be a long range operation.
- Offshore operators involved in the February lease sale face serious economic problems. Many made their bids on the basis of being able to make at least two completions per well.
- The Mouton decision has raised pertinent questions concerning the Tidelands decision. When will the 3-mile line be determined? After it is determined, will the U.S. Geological Survey handle its own proration? If so, there is a chance the federal agency will take a closer look at the offshore picture and perhaps ease up on restrictions. Although it has an agreement whereby Louisiana regulations include federally owned offshore lands, the Interior Department recently announced a plan to study the possibility of separate control of production rates in the federally owned areas.
- Some operators believe there is a possibility that money now being spent on Louisiana offshore operations may be diverted to other areas.
- One major operator said, "Our current drilling program probably will be sharply curtailed at the earliest possible date, and future drilling will be restricted to gas operations only. We simply cannot afford to make single completion offshore."

The picture isn't all black . . .

Although current economic conditions are far from favorable for offshore operations, the Investment Management Department of Calvin Bullock reports the following optimistic long range outlook:

Excellent prospects

The Gulf of Mexico is one of the most promising oil and gas areas in the United States.

Huge reserves

At the end of 1959, Louisiana offshore crude reserves were estimated at nearly 1.6 billion barrels, natural gas reserves at 10 trillion cubic feet. Some believe these figures are only about half the ultimate total. (Current estimates are about the same for crude, about 12 trillion cubic feet for gas.)

High reserve ratio

On a per foot drilled basis, Louisiana offshore operations have been finding four barrels of crude oil for every one found onshore. On a per well basis, the ratio is about 10 to 1 i.e., each offshore gas well drilled develops almost 22 billion feet of reserves, compared with a 2½ billion cubic feet per well average in the United States. Each offshore oil well drilled proves up approximately 660,000 barrels of reserves, compared with a U.S. per well average of 60,000 barrels.

Lower cost—in the long run

Since the end of 1956, when the trend changed from wildcat to development drilling, the increased reserves in the Gulf of Mexico have been proven at a cost of 50 cents to 60 cents per barrel. Thus, even though total cost figures will remain high, per barrel figures will continue to show that these huge expenditures are developing the lowest cost petroleum reserves in the United States.

Trends in Louisiana offshore drilling activity . . .

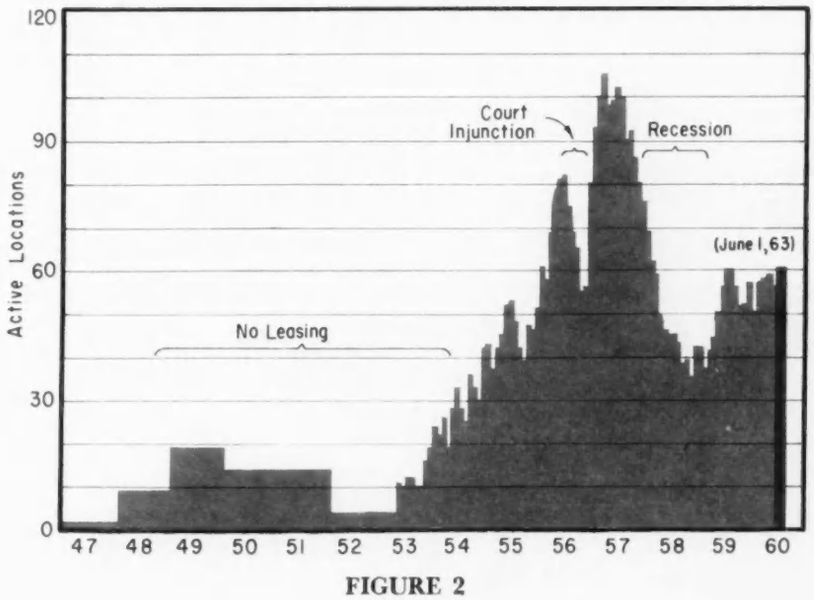
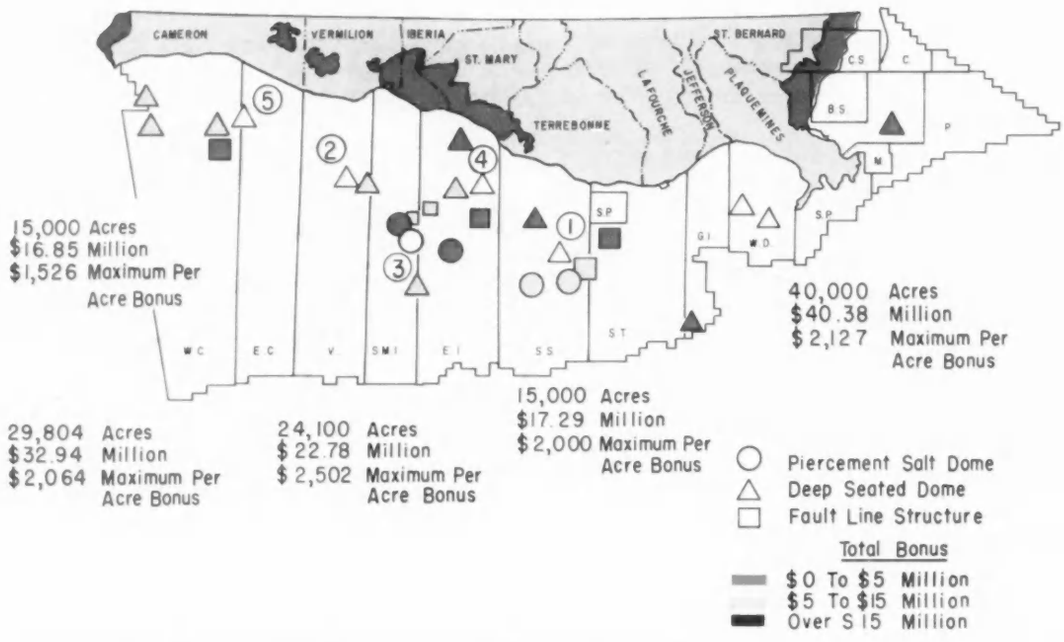


FIGURE 2



Legend

1. Highest priced acreage was in Ship Shoal area. This deep-seated structure sold for more than $40 million.
2. Deep-seated structure in Vermillion area brought second highest price—$32.9 million.
3. Third highest price, $22.7 million, was paid for piercement dome in South Marsh Island area.
4. Deep-seated structure in Eugene Island area was fourth, selling for $17.2 million.
5. Fifth highest price, $16.8 million, was paid for deep-seated structure offsetting East Cameron gas production.

FIGURE 3—Operators paid $246.4 million for 454,046 acres in the February 1960 lease sale. Acreage includes 27 structures—5 salt domes, 16 deep-seated, 6 fault lines.

May outpace domestic earnings

When the Tidelands decision is untangled and market conditions improve, oil companies with large spreads of choice acreage will be favorably situated to outperform the domestic industry in earnings from production of oil and natural gas.

Estimates are that 72 percent of all offshore wells drilled are successful, far better than the onshore record. However, higher offshore costs make a high success ratio mandatory.

Through last April 1, operators had drilled 3,091 wells in the Louisiana offshore area. Of that total, 1,799 were oil wells, 418 were gas wells, and 874 were dry holes (28.2 percent).

But, it isn't bright, either . . .

If you believe offshore operations are "easy pickins," take a look at the other side of the coin.

At the time of the Mouton ruling, production of oil and condensate was approximately 226,000 barrels per day, and gas production was averaging 909 million cubic feet per day.

There currently are about 3,375,000 acres under lease. The accumulative investment in this acrage is $616,266,-000. At the February lease sale, a total of 454,046 acres was sold for a total of $246,379,283.

The industry's total investment in offshore Louisiana is an estimated $3 billion, with an estimated $600 million in revenues above operating expenses. The current expenditure rate, exclusive of lease purchases, is approximately $250 million per year, with a current income rate (above operating expenses) of approximately $200 million per year.

Further evidence that offshore is no bed of roses was graphically presented at a meeting of the Gulf Coast Section, Society of Petroleum Engineers monthly meeting last May. S. V. McCollum, general manager, Southeastern Division, Tennessee Gas and Oil Company, was the speaker.

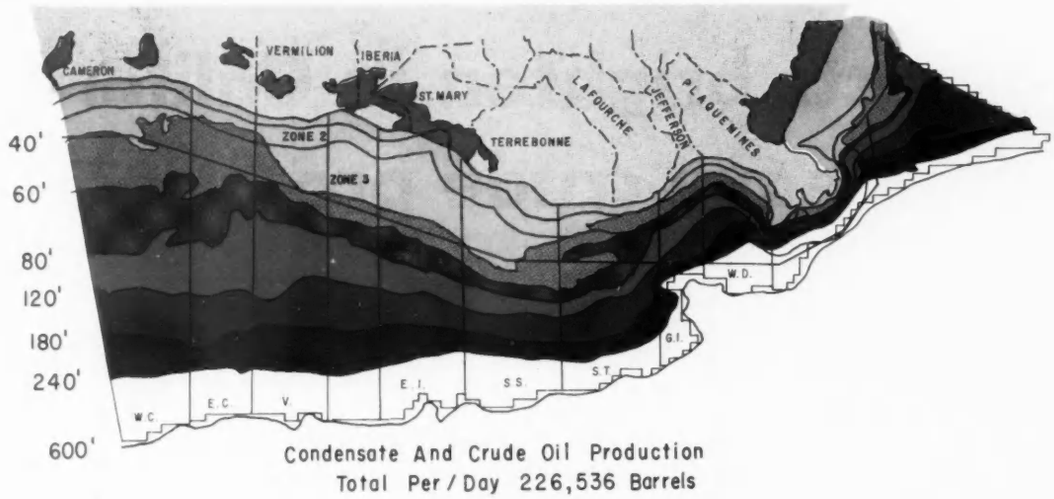
He listed the following basic problems of offshore operations:

1. Time lag between investment and income. Assume you bought 10,000 acres of top quality prospect at the last lease sale. You would have spent about $15 million.

The drilling prospect turns up pretty good, and you make a gas discovery in 75 feet of water, 40 miles from a market. You commence development to prove up reserves and hope they are big enough to warrant a pipe line.

You end up drilling 8 wells, 2 of which are dry, and you find you have 250 billion cubic feet of gas reserves.

Offshore acreage production in relation to water depths . . .



Condensate And Crude Oil Production
Total Per / Day 226,536 Barrels

Up To 40' (3.4 Million Acres)	40-60' (2 Million Acres)	60-80' (1.7 Million Acres)	80-120' (1.9 Million Acres)	120-180' (2.3 Million Acres)	180-240' (1.8 Million Acres)
120,960	82,483	21,057	704	1,332	?

Gas Production Total
Per Day 909,180 Mcf

Up To 40'	40-60'	60-80'	80-120'	120-180'	180-240'
606,792	281,109	21,279	0	0	0

FIGURE 4

This has taken two years and another $8.5 million, making a total of $23.5 million spent. And still you have no income.

Meantime, you have been negotiating for a gas sale, and have applied to the Federal Power Commission. Finally, after another 18 months, you get permission to sell the gas at some figure.

So, after $23.5 million and four years you start to sell gas. Your return on your investment? If you run a taut ship, you might realize 8 to 10 percent return per year. Will this cover the little fields?

2. Small fields. Almost half the gas fields in the Gulf of Mexico have reserves of less than 100 billion cubic feet each. More than one-third of the gas fields are not even connected to pipe lines.

3. Costs. Operators haven't even made a dent in this one. For example, a mobile drilling barge capable of operating in 100 feet of water costs about $12,000 per day, including casing, transportation, etc. A construction barge costs about $10,000 per day. Also, you have higher rigging up costs, not to mention providing catering services for the crew, plus higher cementing, logging, and labor expenses.

Then there are the millions of dollars spent on technical improvements—and multiple completions are just one example.

At the February lease sale, 18,500 acres were purchased in water depths from 180 to 300 feet; 11,500 acres were purchased in water depths of 300 feet or more. The deepest water depth drilled to date was the Gulf Oil Corporation well in South Timbalier in 205 feet of water, from a tender and four-pile platform.

At present, the water depth limit for available mobile equipment is 150 feet.

Marine operators report they have on the drawing boards a drilling platform capable of drilling in 300-foot depths. They believe they have the anchorage problem solved to this depth.

Many operators are studying the feasibility of using floating equipment with underwater completion.

Other costly problems still not completely solved include underwater crude oil storage, sand control, excessive workovers and corrosion.

4. Allowables and spacing. At the time of the Mouton ruling, the allowable for a 12,000-foot oil well was 185 barrels per day. To overcome this and keep their heads above water, operators must make multiple completions. They cannot afford to drill oil wells and make single completions in deep water.

5. Dry holes. Twenty-eight percent of all wells are dry. This is not good enough. The success ratio of exploratory wells is good, but development wells need to be better.

After reviewing the pros and cons of offshore drilling, three facts stand out:

1. Whether the Mouton ruling on multiple completions was a lesser evil than cutting the depth bracket percentage again, or adopting a formula based on depth and well spacing, is debatable.
2. The current setback, though it eats deep into offshore operators' pocketbooks, is a temporary situation.
3. The offshore area at present is no economic plum. However, there is no question that the reserves are there—if operators can afford to stay around long enough to reap the rewards. **—The End**

Prospects brighten in California for heavy crude producers

By Gilbert M. Wilson
Western District Editor

A RAY OF CAUTIOUS OPTIMISM is beginning to be felt among hard-pressed California producers, particularly those producing heavier gravity crudes.

Demand is increasing, new contracts are being signed, below-posting discounts are drying up, most producers now can sell all they produce and, in the opinion of one major company prospects are good that a modest increase in the price of heavy crude might be expected within six months to a year if favorable conditions continue.

This represents a significant turnabout from conditions that have existed during the past two years; a period during which heavy crude prices dropped by as much as 90 cents to $1 per barrel in the lowest gravities; shut in production climbed to as much as 50,000 barrels per day, and when an even greater quantity had to be sold at distress prices ranging to as much as 70 cents per barrel below the already-low posted prices.

Although some production presently is being sold at discount prices, and approximately 5,000 barrels per day still remains shut-in, the situation is improving rapidly.

New contracts signed. Evidence of the improved conditions became apparent about two months ago when Standard of California announced it was signing 6-months "evergreen" contracts for heavy crude. Reportedly, the company has acquired some 1,500 to 2,500 barrels per day of heavy oil through these new connections. The present contracts, renewable at the end of six months if agreed upon by both parties, are in sharp contrast with month-to-month contracts commonly written only a year or two ago. At the time of the announcement, telling of the new longer-term contracts, Standard gave as reasons a renewed demand for heavy fuel oil and movement of heavy crude to the East.

Many independent producers who have not had pipe line connections, or who have had to sell on a spot basis, recently have had offerings from some independent refiners which indicate a narrowing of the gap between offered and posted prices.

Reese H. Taylor, president and board chairman of Union Oil Company, recently said the West Coast oil industry had made "good progress" in reducing inventories. Although much of the surplus, a high percentage of it being heavy fuel, had been sold in eastern markets at little profit, some surpluses still remain in some products.

Heavy crude underpriced. More recently another industry executive, George Getty II, president of Tidewater Oil Company, commented on the improved tone of markets for both crude and products and said he believed heavy crude prices might rise by perhaps 10 cents per barrel within the next 6 to 12 months.

Right now, Getty said, heavy crudes appear to be underpriced by about that much and, if product prices continue to hold firm and inventories maintain their downward trend, he would expect heavy gravity crude prices to strengthen. By year-end, discounted crudes should be at a minimum.

Concurrent with a rise in the price of heavy crude, Getty would expect prices of high gravity crudes to drop by about the same amount, due, in part, to the increasingly higher utilization of heavy crudes and so-called bottom-of-the-barrel products.

Demand up. A summary of District V statistics reported by Oil Producers Agency of California reflects the improved conditions during the first quarter of 1960. Demand for all crude and products totaled 1,434,000 barrels per day, an increase of 79,000 barrels daily, or 5.8 percent higher than the same quarter last year. Stocks were lowered, during the first quarter, at a rate of 96,000 barrels per day, compared with a decrease of 44,000 barrels per day in the same 1959 period.

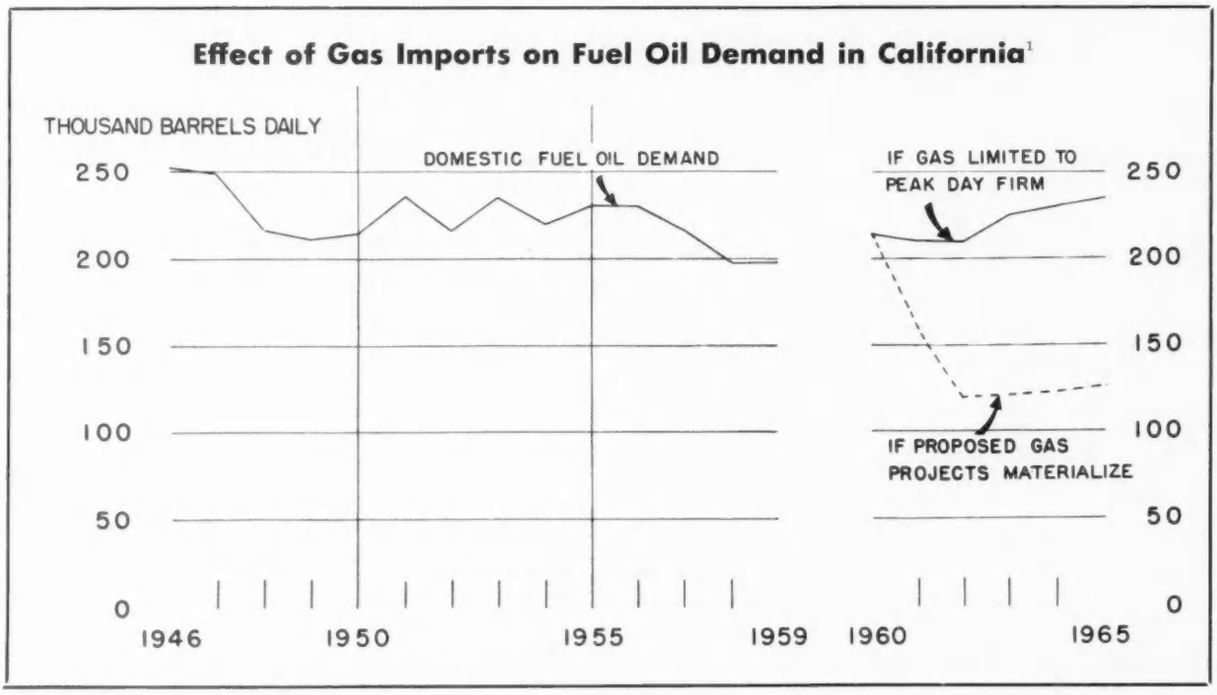
Residual fuel oil demand during the first quarter was 367,000 barrels per day, or 9 percent higher than the demand experienced in the like 1959 period. Inventories of residual fuel during the first quarter were reduced at a rate of 81,000 barrels per day, compared to a drop of only 45,000 barrels per day in the same 1959 period.

The California oil industry, with nearly one-third of its crude oil production ranging from 20 gravity downward, necessarily is affected to a major degree by the fluctuations and often-times distressed price conditions of fuel oil markets.

Reflecting the increased demand and firming markets for heavy oil is the pick-up, in recent months, of the number of rigs running in heavy oil fields of the state. In one such field, for example, a major company reportedly is making plans for drilling, as a long term project, as many as 300 to 400 proven, inside locations. Numerous other companies also have started to drill proven locations in a half-dozen other heavy oil producing fields in the state.

Encouraging factors. The increase in demand for heavy fuel oil during the past few months can be attributed to a number of factors, chief of which are:

- Increased civilian demand which, for the first quarter of this year, was up sharply over that for the same period in 1959
- Demands of utilities which, due to a dry winter in the mountain



areas has created a shortage in hydroelectric power and a corresponding increase in need for heavy fuel oil

- Abnormally large offshore shipments, much of which went to East Coast markets at greatly reduced prices

A rapidly expanding population in the West Coast area, estimated to be increasing at a rate of about 3½ percent annually, together with an increasingly broader industrial base, provide additional grounds for guarded optimism as to the future steady demand for heavy fuels.

With the exception of a big "if" in the matter of natural gas and how much of it will be imported into the region during the next few years, the growth in demand for heavy crudes, and the heavy fuels made from them, would appear to be from two to three percent annually, in the opinion of several industry authorities. However, the long term prospects for heavy crude and heavy fuel oil markets are less certain.

Gas imports displace fuel oil. The West Coast region, an attractive market for out-of-state natural gas and already served by several big-inch transmission lines, will have a new supplier when the Transwestern Pipeline bringing gas from West Texas is completed late this summer.

In addition, applications have been made for two other major gas transmission lines, one from Western Canada, the other from the Rocky Mountain area. Both would bring gas into the West Coast area.

Concern is expressed in some quarters that should these new lines deliver natural gas in excess of that needed to meet the peak firm domestic requirements, the impact on fuel oil demand will be severe.

In the opinion of Howard G. Vesper, president of Standard Oil Company of California, Western Operations, Inc.,[1] fuel oil demand could be as much as 100,000 barrels per day below the level it otherwise would attain if the proposed new gas lines materialize and bring in gas at a rate in excess of those firm daily requirements. He warned that the impact upon California crudes, particularly heavy crudes, would be obvious. He pointed out, further, that "it seems plain that if natural gas is permitted to drive fuel oil from the market place, a fuel monopoly would result which would certainly not be beneficial."

Cracking, coking to increase. Bringing in premature supplies of natural gas would have a direct bearing on the outlook for California producers. Catalytic cracking might have to rise from the current 35 percent to 42 percent of crude distillation capacity and coking up to 12 percent from 6 percent.

From the standpoint of the producer, Vesper continued, such conversions are a costly and unsatisfactory solution to the problem of surplus fuel oil. Such processes are economic only with low cost crude and, in themselves, would not benefit the price structure. With such equipment in service, a lesser quantity of crude is needed to make a given volume of light products which, in effect, reduces the demand for crude.

Future prospects. Looking at both the near-term and long-term aspects, Vesper summarized the California producer's prospects this way:

- Unless dampened by premature influx of natural gas, demand will experience a "sizeable" growth over the next five years
- California producers, in a large measure, will continue to serve their proper share of the western market providing prices of their crude and products remain competitive with incoming supplies from nearby parts of the U.S. and Canada
- Prices for both crude and products in the West are, and will continue to be tied to prices in other U.S. areas and, as a consequence, prices of western crudes will be able to advance only as prices advance generally elsewhere in the country.

LITERATURE CITED

[1] "What's Ahead for the California Oil Producer by 1965?" by H. G. Vesper, president, Standard Oil Company of California, Western Operations, Inc., presented at API Pacific Coast District, Division of Production, Los Angeles, May 12, 1960.

Unique gas lift hookup used to dewater gas wells

Initial single well installation recovers 90 Mcfd production previously vented and wasted. Portable compressor unit is feature of simple, closed rotative system

By J. A. Ziser, Engineer
Colorado Oil and Gas Corporation,
Liberal, Kan.

Colorado Oil and Gas Corporation has recently installed a small, rotative gas lift system on a gas well in Greenwood field, Kansas, for the purpose of removing salt water from the well bore. The installation includes a skid mounted, 170 Mcfd capacity, belt-driven compressor. Two pressure charged gas lift valves are installed in the well.

This type gas well dewatering technique is unique in that no gas is vented to atmosphere when lifting water. The only gas used (about 4 Mcfd) is that required for fuel for the compressor engine. Prior to installing the closed rotative system, 94 Mcfd was used to jet water from the well through a 1¼-inch syphon string. This gas was vented and wasted. Thus, approximately 90 Mcfd is being saved through use of the closed rotative system. Additional advantages of the technique include:

- One compressor unit may be used for two and possibly three wells.
- If flowing wellhead pressure drops below sales line pressure, gas still can be sold via the compressor.
- Payout was calculated as about 2½ months.
- Once the well has unloaded, gas production can be maintained at a higher rate since the well bore is kept virtually free of water. On the first installation, initial obtainable maximum production was 1,170 Mcfd. After 30 days, the well could be produced at a 2,500 Mcfd rate.

Colorado Oil and Gas Corporation's Farm Mortgage Well 2-33, was completed in February 1956 at a PBTD of 3,064 feet after running 5½-inch casing to 3,094 feet. Forty-five feet of Topeka formation was perforated between 2,950-3,018 feet and 33 feet of Elmont formation was perforated between 2,876-2,926 feet with four shots per foot to obtain an open flow blown down gauge of 6,400 Mcf with a mist of salt water. The 72-20 gage was 20,100 Mcf with a rock pressure of 420 psi. In order to operate the well efficiently and to remove the small volume of salt water (approximately 4 bpd) which would be produced with the gas, a 1¼-inch syphon string was run on completion and set at 3,062 feet. The syphon string was equipped with three jet collars as follows:

Depth from Surface	Size Holes
2364 feet	2 Holes—0.027 inch
2614 feet	2 Holes—0.037 inch
2914 feet	2 Holes—0.047 inch

Also, an intermitter was installed to keep the well bore clean with a minimum of operating labor.

Gas production for the Greenwood field is allocated by deliverability tests taken during February and March of each year. Test results for Farm Mortgage 2-33 are as follows:

Year	Deliverability Test	Rock Pressure
1956	4,846 Mcf	423 psi
1957	4,310 Mcf	405 psi
1958	3,763 Mcf	378 psi
1959	3,504 Mcf	352 psi

For the first three years of operation, no major problems occurred and monthly allowables were easily produced; however, water production steadily increased over this period. Starting in June 1959, the current allowable could not be produced from this well due to salt water accumulation in the well bore. The syphon string could not be used to remove all water which entered the well bore at the gas production rate necessary to meet allowable requirements. Current allowables and runs for June, July and August 1959 are listed below:

Month	Current Allowable	Runs
June 1959	30,295 Mcf	19,070 Mcf
July 1959	21,990 Mcf	11,784 Mcf
Aug. 1959	23,378 Mcf	11,077 Mcf

A test run on removal (using the syphon string) of salt water from the well during the first week in September 1959 showed that 28 bwpd were being produced using 94 Mcf gas. Thus, water removal efficiency was 80 cu.ft./gallon of water when the well was produced at a rate of 1,500 Mcf at a flowing wellhead pressure of 280 psi. (Subsequent tests taken after installation of the rotative gas lift system showed the well did not produce this much water after the well had cleaned up). During September 1959, the maximum rate obtainable after being on the line three days was 600 Mcf/day, and after 5 days, 400 Mcf/day.

Since the allowable could not be produced using the 1¼-inch syphon string to remove water, a small rotative gas lift system was installed for test purposes. Figure 1 shows the complete hookup of surface and subsurface equipment.

Subsurface equipment. The 1¼-inch syphon string was pulled and 2-inch EUE tubing was run under pressure and set at 3,047 feet. A perforated sub bull plugged on the end was run on the bottom of the 2-inch tubing string. A 1-inch tubing string equipped with a standing valve and packer on the bottom then was run inside the 2-inch tubing and set at 3,030 feet. Also, a pressure-operated gas lift valve with a pressure setting of 275 psi was installed on the 1-inch string 4 feet above the packer.

Surface equipment. Surface equipment consisted of a skid-mounted, belt-driven, two-stage compressor (LP Bore 5¾-inch, HP Bore 2¼-inch, Stroke 5½-inch) with a rating of 170 Mcfd at 18 psi suction pressure and 825 psi discharge pressure.

The unit was equipped with automatic shutdown switches for high or low suction pressure, high or low interstage pressure, high or low discharge pressure, fluid, high temperature and low oil pressure. Rubber hoses were used for suction and dis-

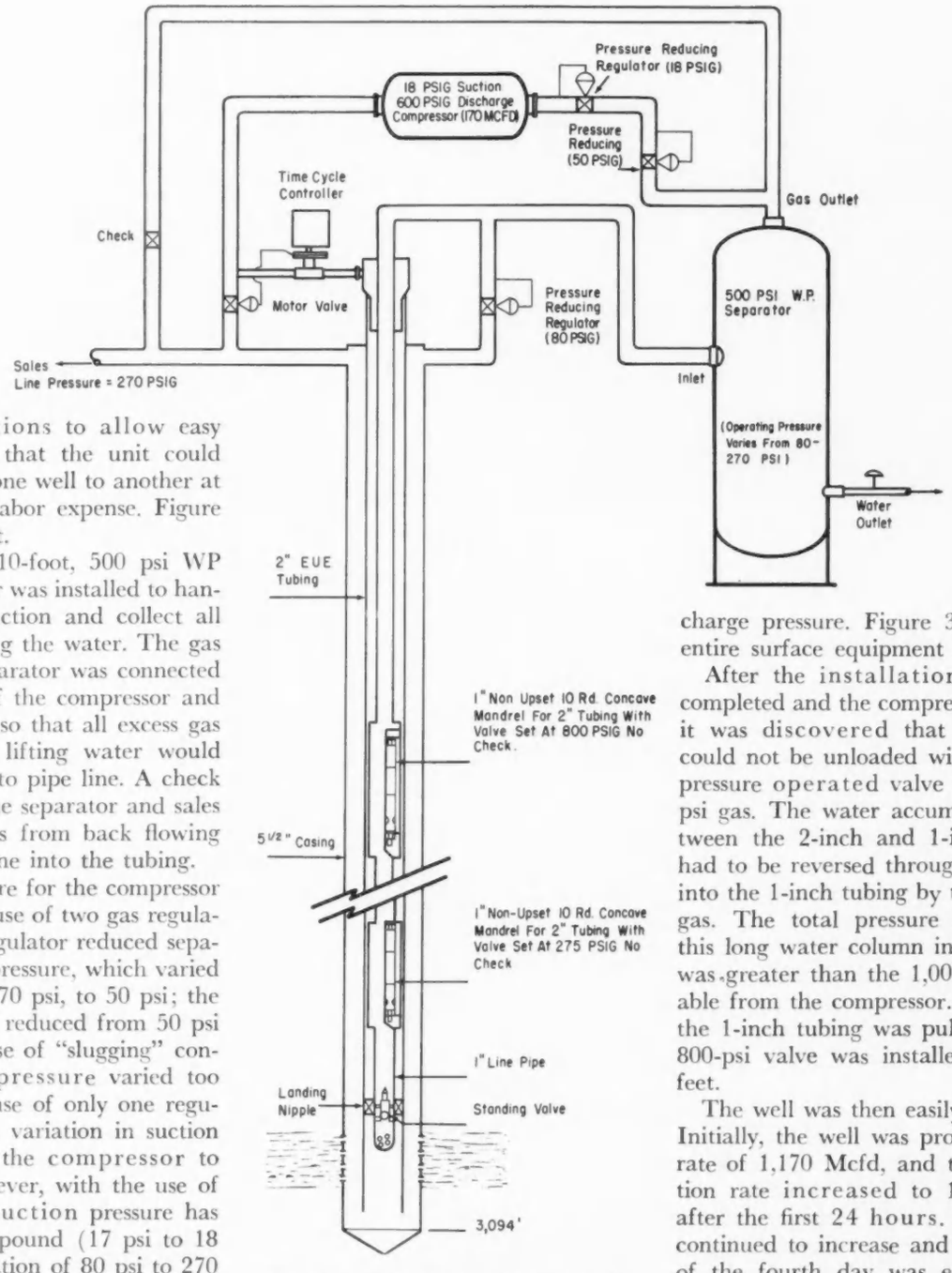

Pressure Reducing Regulator (18 PSIG)
18 PSIG Suction 600 PSIG Discharge Compressor (170 MCFD)
Pressure Reducing (50 PSIG)
Time Cycle Controller
Gas Outlet
Check
Motor Valve
Pressure Reducing Regulator (80 PSIG)
500 PSI W.P. Separator
Sales Line Pressure = 270 PSIG
Inlet
(Operating Pressure Varies From 80-270 PSI)
Water Outlet
2" EUE Tubing
1" Non Upset 10 Rd. Concave Mandrel For 2" Tubing With Valve Set At 800 PSIG No Check
5 1/2" Casing
1" Non-Upset 10 Rd. Concave Mandrel For 2" Tubing With Valve Set At 275 PSIG No Check
1" Line Pipe
Landing Nipple
Standing Valve
3,094'

FIGURE 1—Colorado Oil and Gas Corp. has installed this unique closed rotative gas lift system to dewater gas wells in Mid-Continent area. The system, installed in lieu of a conventional syphon string, used approximately 4 Mcfd gas for compressor engine fuel. No gas is flared or wasted.

charge connections to allow easy hookup and so that the unit could be moved from one well to another at a minimum of labor expense. Figure 2 shows this unit.

A 16-inch x 10-foot, 500 psi WP vertical separator was installed to handle water production and collect all gas used in lifting the water. The gas outlet of the separator was connected to the suction of the compressor and to the sales line so that all excess gas not needed for lifting water would be sold directly to pipe line. A check valve between the separator and sales line prevents gas from back flowing from the sales line into the tubing.

Suction pressure for the compressor was reduced by use of two gas regulators. The first regulator reduced separator operating pressure, which varied from 80 psi to 270 psi, to 50 psi; the second regulator reduced from 50 psi to 18 psi. Because of "slugging" conditions, suction pressure varied too much with the use of only one regulator. Too much variation in suction pressure caused the compressor to shut down; however, with the use of two regulators, suction pressure has varied only one pound (17 psi to 18 psi) with a variation of 80 psi to 270 psi on the separator.

The return line from the 1-inch tubing was tied into the inlet of the separator. Also, a 1-inch line from the casing was tied into the return line and a 1-inch gas regulator installed so that a constant gas supply for the compressor would be available even if the 1-inch tubing was logged.

The compressor discharge was connected into the annular space between the 2-inch and 1-inch tubing strings, and an intermitter with time cycle controller was installed for gas injection. An additional line equipped with a motor valve was installed between the compressor discharge and the sales gas line. Thus, compressed gas not needed for injection to lift water (intermitter closed) is delivered directly to sales (motor valve open).

An automatic pressure control valve was previously tried in place of the motor valve, however, this type valve opened too slowly after the intermitter closed. As a result, the compressor would shut down due to high discharge pressure. Figure 3 shows the entire surface equipment installation.

After the installation had been completed and the compressor started, it was discovered that the tubing could not be unloaded with only one pressure operated valve using 1,000 psi gas. The water accumulation between the 2-inch and 1-inch tubing had to be reversed through the valve into the 1-inch tubing by the injected gas. The total pressure exerted by this long water column in the 1-inch was greater than the 1,000 psi available from the compressor. Therefore, the 1-inch tubing was pulled and an 800-psi valve was installed at 1,626 feet.

The well was then easily unloaded. Initially, the well was produced at a rate of 1,170 Mcfd, and the production rate increased to 1,400 Mcfd after the first 24 hours. Production continued to increase and at the end of the fourth day was easily maintained at 2,000 Mcfd. At this rate, 50 bswpd were jetted from the well by injecting approximately 113 Mcf of gas down the annulus of the 2-inch and 1-inch tubing.

After 15 days production, the well could be produced at a rate of 2,500 Mcfd, and water production had decreased to 17 bpd. After 30 days, water production decreased to 7 bpd.

The compressor used was not specifically sized for this well, but was a unit available for the test. A compressor with an output of 130 Mcfd would be sufficient to meet the requirements of this well, and it is believed that this

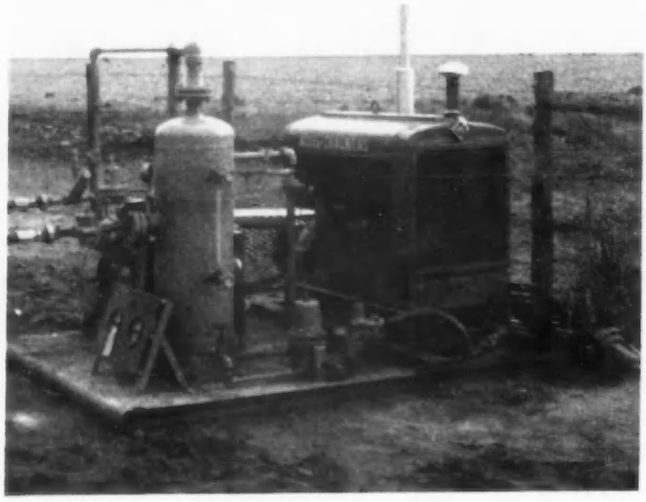


FIGURE 2

This compact, skid-mounted, 170 Mcfd capacity compressor unit (left) was used on the first test well. Note that rubber hoses are used for suction and discharge so that the unit can be disconnected quickly and moved to other locations. Surface

FIGURE 3

equipment required for the closed rotative system includes a 500 psi separator, the compressor unit and associated piping. Equipment used to dewater the initial well is shown at right.

size unit should be adequate to operate the well to depletion.

Costs. Estimated cost of an installation with this size compressor is as follows:

Item	Cost
Compressor and engine 130 Mcf capacity mounted on skid complete with water knock-out	$4,500
Motor valve and controller	275
3 Gas regulators	137
Wellhead for 2-inch and 1-inch tubing	65
1-inch CW line pipe w/J-55 tubing couplings $26.45/100 feet	794
2-inch reg. H-40 tubing $61.14/100 feet	1,834
*Seating nipple, cup hold-down, standing valve	41
2 Pressure-operated valves	374
Well servicing	350
Roustabout labor	200
Miscellaneous connections	100
Total Estimated Cost.	$8,670

Total cost of a closed rotative system may be considerably less than this, dependent upon tubing already in use by the operator. Also, the skid mounted compressor could be used on two or possibly three wells, which would substantially decrease investment costs per well.

Results. The following conclusions were drawn after testing the closed rotative gas lift dewatering system for a four month period:

1. The well bore was easily cleaned and no gas was vented to atmosphere. Only the small volume of gas used to run the engine was used during application of the technique, and all other gas available from the well was sold to pipe line.

2. Initially, 60 bswpd were removed from the well by approximately 113 Mcfd injection gas. After 30 days operation, water production decreased to 7 bpd and gas production stabilized at 2,500 Mcfd.

3. Based on an estimated cost of $8,670 for a closed gas lift system specifically designed for Farm Mortgage 2-33, and an allowable of 30,000 Mcf/month, payout was calculated as 2½ months. However, results were better than expected since 55,000 Mcf were produced during the first full month of operation thus making up back allowable not produced when the well was logged with water.

4. For this specific well, approximately 90 Mcf gas per producing day will be saved using the closed rotative gas lift system instead of the 1¼-inch syphon string and venting water and gas to the atmosphere. If 90 Mcfd were saved and 15 days were required to obtain the allowable, a total of 1,350 Mcf or $165 net would be saved per month. Of course, the volume of gas saved for a particular well will depend upon specific well conditions, volume of water, gas production, etc.

5. Due to the short time the installation has been in use, it is not practical to make a fair comparison between the closed rotative gas lift system and the conventional pumping unit for the removal of salt water from gas wells. At present, the gas lift unit is higher in cost than pumping equipment for a 3,000 foot well; however, with continued use of the gas lift system costs should decrease as improvements are made. Also, with the present allowable rates in the Greenwood and Hugoton fields, one skid mounted compressor unit can be used for two wells, thus decreasing investment cost per well.

Additional testing of this type lift should result in a cheaper installation with increased efficiency. —**The End**

* The cost of a 2-inch seating nipple (to be run on the 2-inch tubing) and the cup hold down (to be run on the 1-inch tubing) is listed in place of the 2-inch x 1-inch packer, since less trouble should be experienced with this type equipment.

About the Author

J. A. Ziser received a B.S. degree in petroleum engineering from The University of Texas in 1945. He was employed by Phillips Petroleum Company after graduation and worked as engineer, district engineer, and assistant district superintendent in the Rocky Mountain area and the Panhandle area of Texas. Since 1955 he has been employed by Colorado Oil and Gas Corporation as an engineer in Liberal, Kansas.

Three-eighths of U.S. oil produced by independents

By L. J. Logan
Associate Editor, World Oil

OUT OF EVERY 8 BARRELS of crude oil produced in the United States in 1959, almost 3 were provided by smaller companies and independent operators and 5 by larger companies.

In most instances, independents had less than 10,000 barrels of production per day each. There are more than 6,500 crude oil producing companies and operators in the country.

Crude production of the independents in 1959 averaged about 2,565,386 barrels daily, or 36.37 percent of the U.S. total of 7,053,671 barrels.

These figures are indicated by the tabulation herewith, based on data in recently issued annual reports.

As shown in the table, 42 larger companies in 1958 had gross crude oil production of about 4,488,285 barrels per day. That was 63.63 percent of the U.S. total.

The independents' share of U.S. production was somewhat smaller in 1959 than in 1958. (WORLD OIL, June 1959, Page 152.)

Company rankings. Texaco Inc. produced more domestic crude in 1959 than any other company. It ranked first also in 1958, but was second to Standard Oil Company (N.J.) in 1957. Texaco's net production of 431,676 barrels daily in 1959 was 6.12 percent of the U.S. total. The company in 1958 accounted for 5.75 percent of the national total by producing 385,867 barrels daily.

Other companies also produced more in 1959 than in 1958 in most instances, as U.S. output was up almost 350,000 barrels daily.

Standard Oil Company (N.J.) in 1959 produced 409,000 barrels net per day or 5.80 percent of U.S. output. That was an increase over 379,200 daily or 5.65 percent of U.S. in 1958. The company ranked second in domestic crude production in both years.

Gulf Oil Corporation remained third. Its net U.S. production of 332,713 barrels daily was 4.72 percent of the national total. Output of 316,886 daily in 1958 was the same proportion.

Shell Oil Company remained fourth and the only other company exceeding 300,000 barrels daily. It had net production of 315,901 barrels daily, up from 301,657, and again accounted for about 4.5 percent of the U.S. total.

Standard of California, Standard of Indiana and Socony Mobil ranked fifth, sixth and seventh, respectively. Each had net production above 200,000 barrels daily. —**The End**

Net Domestic Crude Oil Production of Some U. S. Companies in 1959

(Company's net share; does not include royalty and co-owner interests.)

Data from all available annual reports of U.S. companies with crude production and/or refinery runs around or above 10,000 barrels daily.

Company and Rank in Production	Barrels Daily	% of U.S.
1. Texaco, Inc.	431,676	6.12
2. Standard Oil Company (N.J.)	409,000	5.80
3. Gulf Oil Corp. (incl. 59% of British American's U.S. prod.)	332,713	4.72
4. Shell Oil Company	315,901	4.48
5. Standard Oil Co. of California	271,167	3.84
6. Standard Oil Co. (Indiana)	266,064	3.77
7. Socony Mobil Oil Company	206,000	2.92
8. Continental Oil Company	155,370	2.20
9. Cities Service Company	*†124,745	1.77
10. Phillips Petroleum Company	123,900	1.76
11. Sinclair Oil Corporation	115,229	1.63
12. Ohio Oil Company	97,887	1.39
13. Sun Oil Company	†96,000	1.36
14. Atlantic Refining Company	95,911	1.36
15. Union Oil Co. of California	91,877	1.30
16. Tidewater Oil Company	89,873	1.27
17. Amerada Petroleum Corporation.	82,478	1.17
18. Sunray Mid-Continent Oil Co.	78,515	1.11
19. Skelly Oil Company	64,465	0.91
20. Richfield Oil Corporation	60,619	0.86
21. Pure Oil Company	59,247	0.84
22. Signal Oil & Gas Company	51,325	0.73
23. Honolulu Oil Corporation	37,652	0.53
24. Tennessee Gas Transmission Co. (Tenn. Gas & Oil Co. Div.)	29,500	0.42
25. British American Oil Prod. Co.	26,450	0.37
26. Monsanto Chemical Co. (Lion Oil Company Division)	24,459	0.35
27. Standard Oil Company (Ohio)	24,014	0.34
28. General American Oil Co. of Texas	22,552	0.32
29. Texas Pacific Coal & Oil Co.	20,139	0.28
30. United Gas Corp. (Union Producing Co.)	18,411	0.26
31. Plymouth Oil Company	14,986	0.21
32. Champlin Oil & Refining Co.	14,247	0.20
33. Anderson-Prichard Oil Corp.	14,175	0.20
34. Argo Oil Corporation	13,051	0.18
35. Texas Gulf Producing Company	11,600	0.16
36. Texas Eastern Transmission	10,010	0.14
37. Getty Oil Company	9,472	0.13
38. American Petrofina, Inc.	8,622	0.12
39. South Penn Oil Company	8,194	0.12
40. Ashland Oil & Refining Company	7,282	0.10
41. Colorado Oil & Gas Corporation	†6,681	0.09
42. Quaker State Oil Refining Corp.	1,391	0.02
‡ Total, 42 Companies	3,927,249	55.68
Royalty and Co-Owner Oil Produced, Est.	561,036	7.95
Gross Production, Above Co.'s	4,488,285	63.63
§Remainder of Industry	2,565,386	36.37
Total, United States	7,053,671	100.00

* Includes natural gas liquids. † Includes Canada. ‡ Total excludes the 15,602 barrels daily (0.22% of U.S.) representing 59% of British American's U.S. production counted a second time in figures shown for Gulf Oil Corp. § Companies other than those shown in table herewith. Therefore does not include some non-integrated but larger producing companies shown in table, such as Amerada, Honolulu, General American, Texas Pacific Coal & Oil, Texas Gulf Producing.

Independents have big market for crude

U.S. INDEPENDENT OPERATORS and crude producing companies have a vast market for their crude production at the U.S. refineries of both large and small refining companies. This is true despite large petroleum imports and constant efforts of major companies to develop their own domestic crude production.

The independents and non-integrated producing companies in 1959 produced about 2,823,904 bpd of domestic crude oil. (See table and note its footnote No. 4.) That was equivalent to 35.3% of all the crude run to stills at U.S. refineries and to 40.2% of all domestic crude processed.

These figures are derived from the table herewith. It shows that 34 larger refining companies, accounting for 90.1% of U.S. refinery runs in 1959, produced and controlled 4,229,767 bpd of crude production from their own domestic properties. That volume included their own net production and the usual one-eighth of production purchased from royalty owners.

This gross domestic production of the 34 larger refining companies was equivalent to 52.9% of all crude run to stills at all U.S. refineries and to 60.2% of all domestic crude processed.

For the 34 larger refining companies, gross domestic crude production of 4,229,767 bpd was equivalent to 58.8% of the 7,199,275-bpd refinery runs at those companies' own plants. The remainder of 41.2% of their runs, or 2,969,508 bpd, was provided by crude imports and by purchases of crude from domestic producers.

The 1959 U.S. refinery runs of 7,993,592 bpd included 964,814 (12.1%) foreign crude and 7,028,778 (87.9%) domestic crude.

Besides the 34 larger refiners here listed, there were over 200 independent refining companies, which in 1959 processed 794,317 bpd, or 9.94% of total U.S. crude runs. They, too, imported some crude and generally purchased the rest from independent producers.

The table here ranks the 34 larger refiners in order of runs to stills. It also shows the crude oil self-sufficiency of each company, giving its gross crude production as percent of refinery runs.

The five largest refiners include Standard (N.J.), Texaco, Standard (Ind.), Socony Mobil and Shell. Companies with high ratios of crude production to refinery runs include Gulf, Texaco, Shell, Continental, Ohio and Skelly. —The End

Domestic Refinery Runs and Crude Oil Production of Some U.S. Companies in 1959

(Data from all available annual reports of U.S. companies with refinery runs and/or crude production around or above 10,000 barrels daily.)

Company and Rank in Refining	Total Crude Runs To Stills		Net Domestic Crude Oil Production		Gross Prod. As Percent of Runs to Stills
	Barrels Daily	Percent of U.S.	Barrels Daily	Percent of Runs to Stills	
1. Standard Oil Co. (N.J.)	861,000	10.77	409,000	47.5	54.3
2. Texaco, Inc.	641,378	8.02	431,676	67.3	76.9
3. Standard Oil Co. (Ind.)	598,280	7.48	266,064	44.5	50.8
4. Socony Mobil Oil Co.	561,000	7.02	206,000	36.7	42.0
5. Shell Oil Co.	489,753	6.13	315,901	64.5	73.7
6. Standard Oil Co. of Calif.	478,700	5.99	271,167	56.6	64.7
7. Gulf Oil Corp.	443,328	5.54	332,713	75.0	85.8
8. Sinclair Oil Corp.	441,718	5.53	115,229	26.1	29.8
9. Cities Service Co.	269,041	3.37	124,745	46.4	53.0
10. Tidewater Oil Co.	227,000	2.84	89,873	39.6	45.2
11. Phillips Petroleum Co.	227,000	2.84	123,900	54.6	62.4
12. Sun Oil Co.	216,500	2.70	96,000	44.3	50.7
13. Atlantic Refining Co.	194,413	2.44	95,911	49.3	56.4
14. Continental Oil Co.	179,009	2.23	155,370	86.8	99.2
15. Union Oil Co. of Calif.	172,682	2.17	91,877	53.2	60.8
16. Pure Oil Co.	166,356	2.08	59,247	35.6	40.7
17. Sunray Mid-Continent	154,026	1.92	78,515	51.0	58.3
18. Standard Oil Co. (Ohio)	138,986	1.74	24,014	17.3	19.7
19. Richfield Oil Corp.	137,814	1.73	60,619	44.0	50.3
20. Ashland Oil & Ref. Co.	[1]136,576	1.70	7,282	5.3	6.1
21. Ohio Oil Co.	100,268	1.26	97,887	97.6	111.6
22. Skelly Oil Co.	48,882	0.61	64,465	131.9	150.7
23. Signal Oil & Gas Co.	42,362	0.53	51,325	121.2	138.5
24. American Petrofina, Inc.	39,173	0.49	8,622	22.0	25.2
25. Tenn. Gas Trans. Co.[5]	33,791	0.42	29,500	87.3	99.8
26. Plymouth Oil Co.	31,600	0.40	14,986	47.4	54.2
27. Clark Oil & Ref. Corp.	30,408	0.38	.....	.....	.....
28. Anderson-Prichard	30,074	0.38	14,175	47.1	53.9
29. Monsanto Chemical[6]	29,981	0.37	24,459	81.6	93.2
30. Champlin Oil & Ref. Co.	27,064	0.34	14,247	52.6	60.2
31. Colorado Oil & Gas Corp[7]	17,168	0.21	6,681	38.9	44.5
32. Tex. Eastern Trans. Corp.	15,725	0.20	10,010	63.7	72.8
33. South Penn Oil Co.	9,676	0.12	8,194	84.7	96.8
34. Quaker State Oil Ref.	8,543	0.11	1,392	16.3	18.6
Total 34 Companies	7,199,275	90.06	[2]4,229,767	.....	58.8
Remainder of Industry	794,317	9.94	[4]2,823,904	.....	355.5
Total U.S.	[3]7,993,592	100.00	7,053,671	.....	88.2

[1] Data for 12 months ended Sept. 30, 1959. [2] Gross production including the 3,701,046 barrels daily net production of above companies and an estimated 528,721 barrels daily of royalty and co-owner oil produced by those companies. [3] Includes 7,028,778 domestic crude and 964,814 foreign crude. [4] Gross production of companies other than refiners shown in table herewith. Includes some non-integrated but larger producing companies, such as Amerada, Honolulu, General American, Texas Pacific Coal & Oil, Texas Gulf Producing. [5] Bay Pet. Co. Div. at Denver, New Orleans. [6] Lion Oil Co. Div. [7] Derby Ref. Co. at Wichita, Kans.

How to cement dual tubingless completions

Improved operational procedures provide good primary cement job in first marine multiple slim hole

By R. R. Angel
Senior Production Engineer, Phillips Petroleum Company
Corpus Christi

PHILLIPS PETROLEUM COMPANY has recently completed what is believed the first tubingless dual completion over water. Also, it is believed to be the first operation which included reciprocating multiple strings of tubing simultaneously while cementing.

This operation was in the Copano 74 Fulton Beach field, Copano Bay, Aransas County, Texas. The total depth of the well was 7,450 feet.

In making multiple tubingless completions, obtaining a good primary cement job is a serious problem. Communication between producing zones frequently results from failure of the primary cement job.

One operator said its best cementing success ratio is approximately 60 percent while another reported only one completely successful job out of six attempts at cementing multiple strings. Consequently, considerable effort has been extended in perfecting a technique of overcoming these failures.

The success of Phillips multiple tubingless operation resulted from the following:

- The multiple strings were centralized near the shoe through the pay zones. Rubber centralizers were banded on each string for this purpose.
- Both strings were reciprocated while cementing.
- The strings were cemented with as high an annular velocity as possible using a cementing truck on each string.
- A low viscosity wash solution was pumped ahead of the cement.
- The tops of the tubing couplings on the first string were beveled. Additional recommended practices are:
- Run an odd length of casing joint, or "pup" joint near the pay zone in each string to assist in identifying gamma ray collars while perforating.
- Case at least 50 feet below each producing zone to provide "rat hole" for disposing of lost tools.

Drilling program. A 17½-inch hole was drilled to 122 feet where a string of 13⅜-inch conductor pipe was set and cemented. After the normal nippling up and WOC period, a 12¼-inch hole was drilled to 1,041 feet. A 9⅝-inch surface string was then set and cemented to the surface. Following the WOC time of 24 hours, an 8⅝-inch hole was drilled to the total depth of 7,450 feet.

Mud program

Depth	Mud Wt. ppg.	Viscosity Sec.	Water Loss cc	Mud Type
0-5,000	9-10	35-40	—	Gel, natural
5,000-7,450	9-10	40-48	7-8	Gel, phosphate

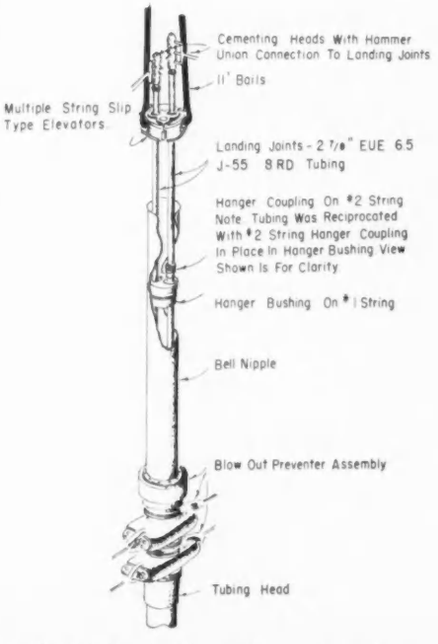

Cementing Heads With Hammer Union Connection To Landing Joints
11" Bolts
Multiple String Slip Type Elevators
Landing Joints - 2 7/8" EUE 6.5 J-55 8 RD Tubing
Hanger Coupling On #2 String Note Tubing Was Reciprocated With #2 String Hanger Coupling In Place In Hanger Bushing View Shown Is For Clarity
Hanger Bushing On #1 String
Bell Nipple
Blow Out Preventer Assembly
Tubing Head

FIGURE 1—Hook-up shown to reciprocate the dual 2⅞-inch tubing strings.

Running the dual strings. The 2⅞-inch OD casing strings were run separately. In addition to the usual precautions observed in the handling and running of casing, each length of tubing was drifted with a 2.345-inch OD drift which was 4 feet in length.

The first string was run at normal speed. On reaching the desired setting depth, a hanger bushing was made up on the top joint, and the tubing string was landed in the head with a landing joint.

The second string was run through the offset hole in the hanger bushing. It was run with extreme caution and at a reduced speed. On reaching the desired setting depth, the hanger

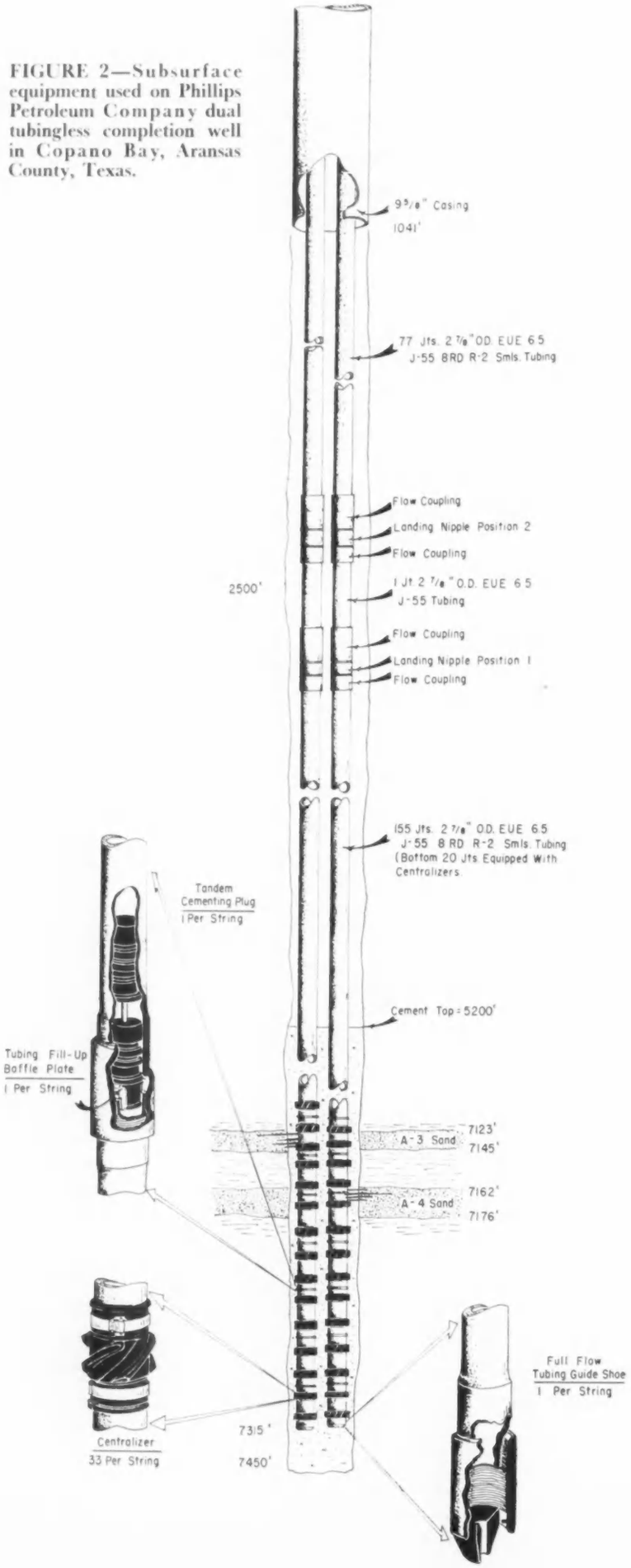


FIGURE 2—Subsurface equipment used on Phillips Petroleum Company dual tubingless completion well in Copano Bay, Aransas County, Texas.

coupling was made up on the top joint and the string was lowered with a landing joint until the hanger coupling seated in the hanger bushing.

A landing joint then was installed in the hanger bushing. Both strings were picked up with the two landing joints using two sets of slips in triple elevators (see Figure 1).

Cementing the dual casings. Cementing heads were installed on both casing strings. The hole was circulated around with mud before mixing cement and the casing strings were reciprocated during this operation. Also, shearing balls were pumped down to shear out the nose of each guide shoe and provide a 2⅛-inch diameter opening for cementing. A wash of 500 feet (open hole length) of bay water was pumped ahead of the cement.

Separate cementing trucks were used on each string. Mixing water was measured to assure that the cement started out both casing shoes at the same time. Each truck mixed and pumped 185 sacks of 13.2 pounds common cement slurry with 10 percent diatomaceous earth. The casing strings were reciprocated through an 11-foot stroke until all cement had been mixed.

At this point, the top of the cement outside the casings was approximately 400 feet above the top of the upper zone. The surface cementing lines were carefully flushed and the cementing plugs were released. The casings were landed in the head and the cement was displaced from both casings with oil at a maximum pumping rate. Both cementing plugs were bumped and the casings were tested to 4,000 psi. The pressure was then bled back to 2,500 psi and held for 8 hours.

Completion. Upon checking the tubing strings with a wireline after cementing, it was found that both strings were plugged at about 4,100 feet. It was determined that the back half of both cementing plugs were

stripped off the center rod when the plugs went through the landing nipples at 2,500 feet. These plugs were pushed to bottom with a ¾-inch tubing string.

Neutron logs were run in both casings, and two attempts to perforate the casings failed because the guns could not be run to the perforating depth. After the first attempt, two days of wireline work were required to clean the rubber from both tubing strings. The perforating guns still could not be lowered to perforating depth. Cement was then scraped from the walls of the casings with wireline tools. Apparently, the front wiper plugs wore out at about 7,100 feet and started bypassing small amounts of cement.

After the cement was scraped from the casings, they were perforated with a 2-inch OD oriented scalloped jet gun, as planned. The lower zone was perforated 7,162-65 feet. Upper perforations were from 7,123-28 feet.

Both zones unloaded without swabbing since oil was left in the casing strings after cementing. Flowing tests established that no communication exists between producing zones. The primary cement job was considered successful. Subsurface equipment. Figure 2 shows a sketch of the subsurface equipment used. Equipment items used on each casing string includes:

- Guide shoe on bottom.
- Stop ring in the third tubing collar. This serves as a stop for the cementing plug.
- Two landing nipples with flow couplings above and below at about 2,500 feet to provide seats for storm chokes.
- 4⅛-inch centralizers spaced two per joint from the shoe to 60 feet above the top pay and one per joint for the next 200 feet.

Surface equipment. A series 900 dual christmas tree was used with a 10-inch series 900 casing head installed on the 9⅝-inch surface casing. Dual 2½-inch block type master valves were used, as well as two single 2½-inch screwed crown valves.

Economics. Successful application of tubingless techniques will result in substantial savings. The following costs are compared for a trouble free 7,200 feet dual completions in Copano Bay similar to the Copano 74.

2½-inch x 2½-inch Tubingless:

Tangibles	$27,200
Intangibles	58,900
Total	$86,100

5½-inch x 2-inch x 1¼-inch Conventional:

Tangibles	$35,500
Intangibles	61,300
Total	$96,800

7-inch x 2-inch x 2-inch Conventional:

Tangible	$ 44,700
Intangible	65,800
Total	$110,500

It is believed that with further refinements of techniques and equipment a saving of $28,400.00 can be realized from the use of 2½-inch x 2½-inch tubingless completion in preference to a 7-inch x 2-inch x 2-inch conventional completion.

—**The End**

About the Author

R. R. Angel is senior production engineer in the Corpus Christi, Texas, District of Phillips Petroleum Company's Production Department. He was graduated from Kansas State College in 1949 with a B.S. degree in mechanical engineering. Before joining Phillips in 1951, he was employed by Dowell, Inc., and the U.S. Department of Agriculture. He served as a district staff engineer and drilling engineer before assuming his present duties.

Don't miss these articles on pages that follow . . .

FORECASTING THE WEATHER IN PERSIAN GULF

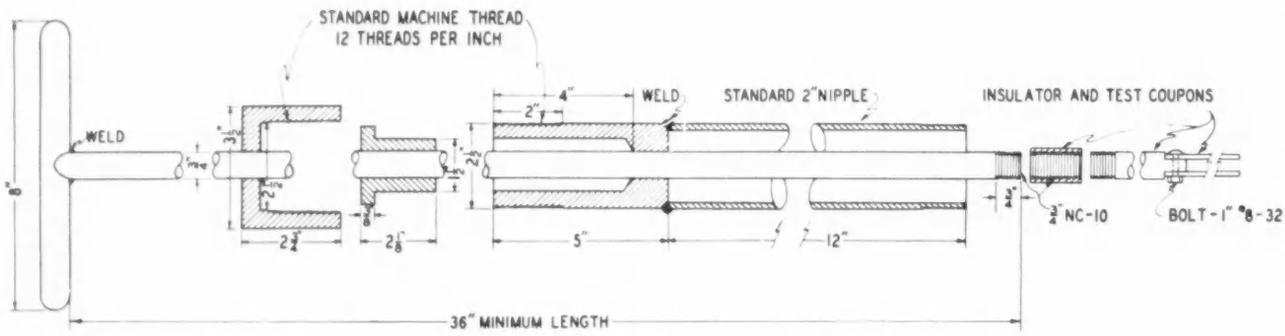
Assembly and movement of offshore drilling platforms becoming much safer.

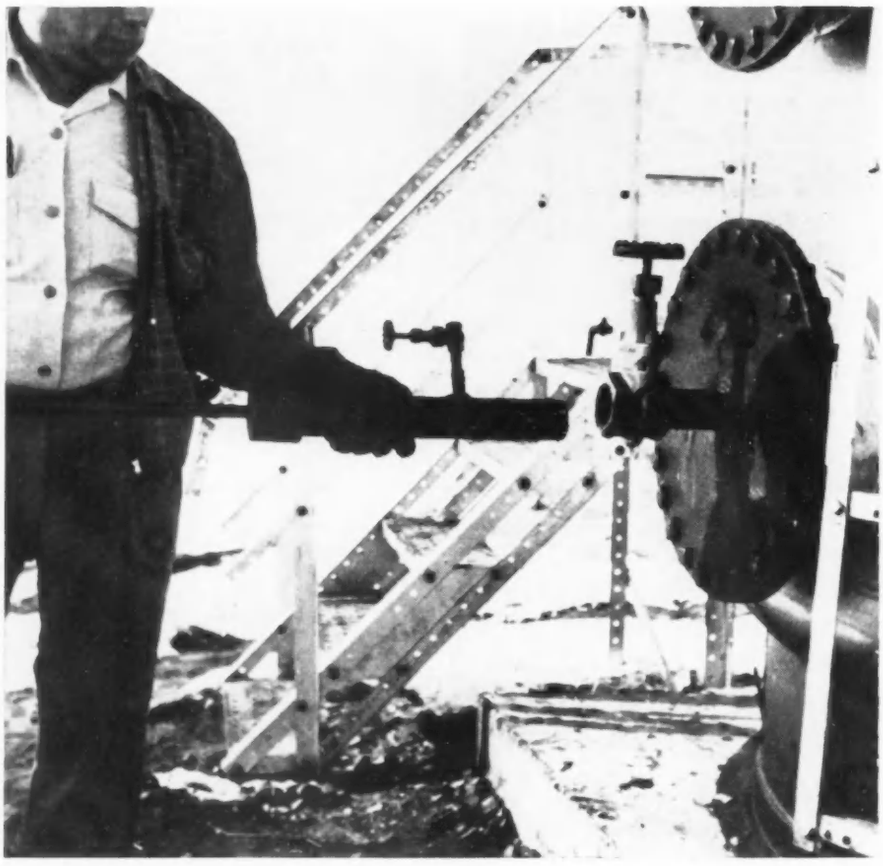
PAGE 198

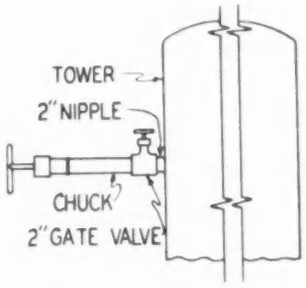
HOW TO DESIGN CLOSED ROTATIVE GAS LIFT SYSTEM

A complete description of the step-by-step calculations that are required.

PAGE 116







DETAIL OF INSTALLATION

FIGURE 1—This simple, easily constructed chuck or coupon holder (above) can be fabricated in the field. It is installed on treaters for continuous coupon corrosion tests. A ½-inch needle valve can be welded to the 2-inch nipple for a bleed.

FIGURE 2—This coupon holder (Figure 1) has been installed on the clean-out plate of a heater-treater. A full open 2-inch valve is installed ahead of the chuck so corrosion coupons can be inserted or withdrawn from the vessel without taking equipment out of service.

In cold weather areas . . .

Practical field techniques cut crude treating costs

Optimum treater temperatures, proper application of chemicals can reduce vapor losses, increase equipment life and eliminate operational hazards

By James W. Hakeman
Assistant Division Manager
Tretolite Company
Edmonton, Alta.

OIL TREATING COSTS can be reduced when optimum treating temperatures and proper chemical assistance are employed. Stock tank volumes can be increased, equipment life extended and hazards reduced. Cold weather problems, such as are encountered in Western Canada, can be solved by careful study of lease equipment and crude conditions.

In oil treating procedures, rigid budgeting has sometimes resulted in apparent operating economies. Frequently, such "economies" are false

because certain fundamentals of oil treating were not considered. This is a natural oversight because there are only two factors wherein change is immediately apparent:

- The condition of treated oil going into the stock tank.
- The rate at which the chemical injector is emptied.

All-important economy factors such as gravity and vapor losses, high fuel consumption, treater scaling and corrosion, etc., are overlooked frequently since they are difficult to measure and not always apparent.

Operating economy depends in part on proper operating temperatures of oil treating equipment. Once chemical demulsifier has destroyed the properties of the emulsifying agent in the common water-in-oil emulsion, the rate at which water will settle depends mainly on droplet size and the gravity differential between water and oil.

Increasing operating temperature is one means of increasing gravity differential. Generally, heating will aid treating to a certain optimum temperature, after which an additional temperature increase is of little value. This optimum temperature level is variable, and may differ from lease to lease and battery to battery. Generally, however, the level may be lowered through proper use of chemicals.

For example, in one case a treating temperature of 160° F. resulted in salable pipe line oil. When chemical demulsifier was added at the rate of one quart per 300 barrels of produced fluid, optimum temperature level was reduced to 128° F. The decreased gravity differential between water and oil was offset by the increased coalescence of droplets resulting from the reaction of the chemical. (As water droplets coalesce, their increased size facilitates settling. Other factors remaining equal, if the size of a droplet is doubled, its settling rate will be quadrupled.)

Prevent gravity loss. Most crude oil in Western Canada is sold on fixed gravity levels rather than on a premium payment scale for an integral of each one or two degrees increase in gravity. Since the disadvantage of gravity loss is lacking, vapor loss remains as one of the most important factors in the relationship between temperature and economics. The accepted average vapor loss figure of 2½ percent by volume represents a considerable loss of income and one which is frequently overlooked.

Many field tests have been conducted to substantiate benefits derived from reduction of excessive treating temperatures. One such case is illustrated in Table 1. Average production on this battery totaled 1,279.5 bopd and 287 bwpd. During the test, the treater was operated at 130° F. and 120° F. At the lower temperature, chemical injection rate was increased 1.349 quarts per day. However, the daily volume of stock tank oil increased 20.7 barrels, with a daily net savings of $48.79. The operator also realized an intangible savings from de-accelerated corrosion and scaling, as well as reduced fuel consumption.

Foamy oil. In another case, a used treater was installed to handle foamy oil production. The average treating rate of similar oil was one quart of chemical per 100 barrels of produced fluid. Laboratory tests indicated the subject crude should treat at that ratio. However, with an initial temperature setting of 160° F., 2 percent BS&W was carried over into the stock tank. Chemical ratio was increased gradually to 4 quarts per 100 barrels of produced fluid with little effect. After reducing treater temperature to 135° F., a decrease soon was noted in the BS&W content of oil going to stock.

At this reduced temperature it was possible to decrease the chemical ratio, and the resulting BS&W content levelled off at 0.5 percent. Installation of a gas separator and preheater decreased chemical consumption and BS&W content to a normal level.

Proper operational procedures can solve cold weather problems in most cases. In a Saskatchewan field, the burner gas supply line of a heater-treater operating at 156° F., periodically became frozen. The supply line scrubber collected large quantities of fluid, and the resulting icing conditions prevented flow of supply gas to the burner. The resulting loss of heat impaired demulsification and made it necessary to recycle large quantities of "bad" stock tank oil. Labor and chemical costs increased because of the required recycling. The resulting treating ratio was one quart of chemical per 70 barrels of oil.

Field tests indicated that a treating temperature of 124° F. was sufficient —a decrease of 32° F. The reduced temperature practically eliminated the large quantities of fluids collecting in the scrubber and freezing no longer was a problem. In addition, average chemical treatment decreased to one quart per 130 barrels of oil because recycling became unnecessary. Thus, chemical costs were reduced by almost one-half. Labor costs and volume loss of oil also were reduced.

TABLE 1—This case history indicates how a reduction in treater temperature can increase stock tank oil recovery and increase profits.

Oil Production (bbls. per day)	Treater Temperature	Chemical Consumption
1279.5	130°	4.696 qts/day
1300.2	120°	6.045 qts/day
+20.7	—10°	+1.349 qts/day

Gross Profit (20.7 bbls. @ $2.40)	= $49.68
Less Increased Chemical Cost	= .894
Net Profit	= $48.786

Cut treater corrosion. Severe corrosion is a costly problem in oil treating equipment. Unfortunately, such corrosion may reach an advanced stage before it is discovered, and even then corrective measures may sometimes be limited by production procedures and economics. For example, installation of corrosion coupon holders in a treater may be delayed until the treater can be shut down.

Visual inspection and equipment failures are final standards for determination of corrosion, but simple intermediary tests provide faster results at less cost.

In Western Canada, corrosion coupons are indicative of corrosion rates in oil treating equipment. A coupon holder is shown in Figure 1.

Corrosion coupons may be installed at most points within a treater. Corrosion rates obtained before and after protective measures indicate effectiveness of such measures. For example, a 4-foot treater was showing signs of severe corrosion. Coupons exposed in the water section had initial corrosion rates of 152 MPY. During a two and one-half year period of corrosion inhibition, 32 sets of coupons had an average loss of 4.32 MPY, or a 97.15 percent reduction in the corrosion rate. Periodic inspection confirmed results indicated by the coupons.

Scaling also was severe. Deposition made removal of the firetubes every three months very difficult. A multi-

purpose compound for combatting scale and corrosion reduced the problem to one of minor importance.

Variable coupon corrosion rates have been noted in the treaters surveyed. Although rates of 20 to 40 MPY generally are severe rates, as much as 180 MPY have been noted. Figure 3 shows a relatively low initial rate, but is of interest since a comparison of corrosive conditions at two different temperatures is presented. In this case, temperature was the prime influence on observed difference, although other factors may have contributed. Decreased corrosion rates (Figure 3) resulted from use of a compound for combatting both corrosion and scale.

Leak detection. "Bad" oil frequently is the first indication of corrosion in treating equipment. Of course, presence of water in treated oil may result from difficulties other than corrosion. In either case, use of concentrated dyes has been helpful in solving mechanical problems.

The dye is dissolved in about one quart of water, and is injected into the treater input line. Samples of oil going to stock are caught periodically at the treater outlet and centrifuged. If samples contain water, dye will be evident after it has had time to pass through the treater. The elapsed time required for the dye to traverse the heater depends on the path it follows and on the volume of produced fluids.

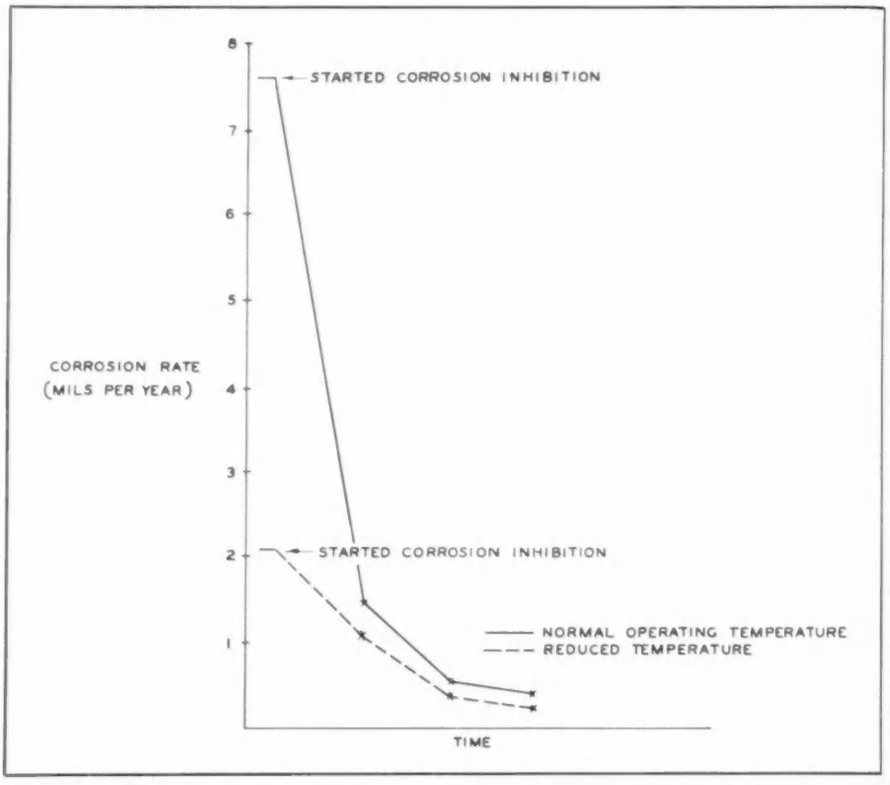


FIGURE 3—Here is a comparison of treater corrosion at normal operating temperature and at reduced temperature. The comparison was made before and after corrosion inhibition.

For example, a hole in a heat exchanger resulted in dye returns in a few seconds. In another, the treater hay section was channelled and dye was recovered in 20 minutes. Four hours would have been normal. The dye method should assist in determining whether a treating problem is mechanical or chemical.

Flow line pressures reduced. During the winter, some flow line pressures (from wells to battery) increase considerably. This increase sometimes can be attributed to high viscosity of the produced emulsion. Lowering the viscosity of the emulsion will ease this added load which may become hazardous.

Such a situation existed in producing field north of Edmonton, Alberta. During the winter, pressures in several 3-inch flow lines increased 220-260 psig. After installing beam operated chemical injectors at each well location, line pressures decreased to 30-40 psig. Total chemical consumption was not increased since a correspondingly smaller quantity of chemical was required at the battery header. While the viscous flow line emulsion required a slightly higher treating ratio, the improved agitation or mixing from well to header, compensated for this.

Table 2 lists chemical treating ratios, flow line pressures and atmospheric temperatures recorded during a field test similar to that mentioned above. As before, line size was 3-inches and a beam-operated chemical injector was used to inject the demulsifier. A minimum line pressure of 33 psig was reached at a treating ratio of 0.26 quarts per 100 barrels of produced fluid. A subsequent increase of 50 percent had no noticeable effect on this pressure.

Periodic review and renewed application of treating fundamentals often can be profitable. Without such reviews, it is only natural that *improper* oil treating procedures could become accepted routine.

TABLE 2—Flow line pressure increases due to viscous emulsions are eliminated by injecting chemical at the well.

Quarts of Chemical per 100 bbls. of Produced Fluid	Flow-line Pressures	ATMOSPHERIC TEMPERATURES	
		Maximum	Minimum
None	125 to 150	..	..
0.196	36	13°	5°
0.260	33	18°	2°
0.4	33	20°	—3°

ACKNOWLEDGMENT

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About the Author

James W. Hakeman attended the University of Iowa and Drake University. He graduated in 1942 with a B.A. degree in mathematics and physics. Following service in the U.S. Navy he was connected with Look Magazine in the advertising department, was self-employed for a period of time, and was later employed by Halliburton Oil Well Cementing Company. He joined Tretolite Company in 1953 as a field engineer in Longview, Texas, and then served as a corrosion engineer, stationed at Shreveport, La., prior to being transferred to Edmonton, Alberta, as assistant division manager.

Arctic Islands allow fast photogeologic evaluation

Canadian Islands have good Paleozoic prospects; mobile belts contain thick strata, many domes

By Fred C. Brechtel
Executive Vice President
and Don B. Gould, Administrative Geologist
Geophoto Services, Ltd., Calgary

AIR PHOTOGRAPHS provide an exploration tool particularly adapted to the oil search in the Arctic Islands. Location of the Arctic Islands and necessarily high transportation costs result in a relatively high cost per man hour on outcrop. The field season (June 15 to September 1), is not only short, but also persistent fog may hamper aerial reconnaissance or prevent movement of field parties by aircraft, further shortening the effective length of the season.

The Arctic Islands offer nearly ideal conditions for photogeologic mapping. Forest cover is absent. Glacial deposits are restricted mainly to the southern islands. Snowfall is light, and away from ice caps and glaciers in the higher eastern part of the archipelago, snow melts rapidly in the continuous summer daylight.

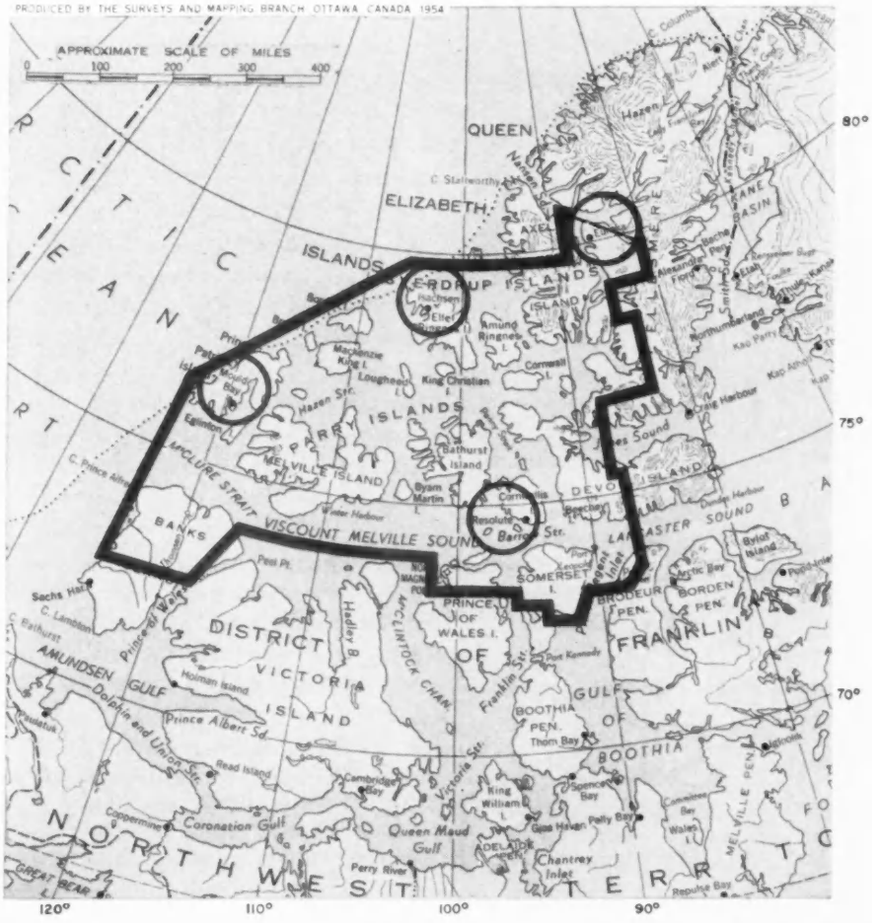


FIGURE 1—More remote northwestern portion of Canadian Arctic Islands is prospective for oil and gas. Applications for exploratory permits covering 130 million acres were filed in the area enclosed by the dashed line during 1959.

Activity increasing. Interest in the Canadian Arctic Islands as a potential oil province is largely an outgrowth of investigations made by the Geological Survey of Canada over the past 10 years. Preliminary studies near weather stations at Resolute, Eureka, Mould Bay and Isachsen (Figure 1) were expanded in 1955 by Operation Franklin, a helicopter-supported program of reconnaissance geologic mapping. Information obtained by ground observation at key localities later was extrapolated on trimetrogon air photographs to form the basis for preliminary geologic maps.

Geological Survey activities not only emphasized large sedimentary basins in the Arctic,[1] but also demonstrated the feasibility of field work with modern equipment. Occurrence of bituminous materials, reported by early explorers, was verified. Conditions were shown to be comparable to those in other geologic provinces which produce oil.

Government emphasis on northern development is largely based on these findings, and led to filing of applications during 1959 for exploratory permits covering 130,193,964 acres in an area including most of the Queen Eliz-

abeth Islands, shown by the dashed line in Figure 1. This part of the archipelago is the most remote, but it is believed to have the greatest oil potential.

REGIONAL GEOLOGY

Arctic Canada, north of the mainland, comprises a land area of approximately 500,000 square miles, a little less than that of Alaska. About half of this area offers no prospects for finding oil. Much of the eastern and southern margin of this area can be excluded because of proximity to the Canadian Shield, with pre-Cambrian igneous and metamorphic rocks at or near the surface. Conditions appear favorable in the remaining area, particularly in the northwestern part, where a maximum aggregate thickness of Paleozoic and younger sediments as great as 80,000 feet occurs, combined with a variety of structural conditions.

Rocks exposed in the Arctic Islands generally are successively younger outward from the stable Shield area to a bordering coastal plain. As in other parts of the continent, the stable area is separated from the coastal plain by a *relatively mobile zone* which includes folded belts and troughs of sedimentation. Three main orogenic events since the pre-Cambrian are Caledonian (late Silurian), Variscan (post-Devonian, pre-middle Pennsylvanian) and Alpian (Tertiary).

The Arctic Archipelago is subdivided by the Geological Survey of Canada into four major tectonic and sedimentary regions as illustrated by Figure 2—Shield, Arctic Lowlands and Plateaus, Innuitian Region and Arctic Coastal Plain.[2]

The Boothia Arch extends northward from Boothia Peninsula along the west shore of Somerset Island, separating the Jones-Lancaster Basin to the east from the Melville and Victoria Strait basins to the west. The Jones-Lancaster Basin is occupied mainly by Ordovician and Silurian carbonates with some clastics of possible Cambrian age. Above the carbonates is a clastic sequence of late Silurian or early Devonian age, mainly conglomerate containing granite boulders derived from the pre-Cambrian of the Boothia Arch and indicative of the Caledonian orogeny. Maximum thickness of sediments in the Jones-Lancaster Basin is unknown, but it is believed to be only a few thousand feet.

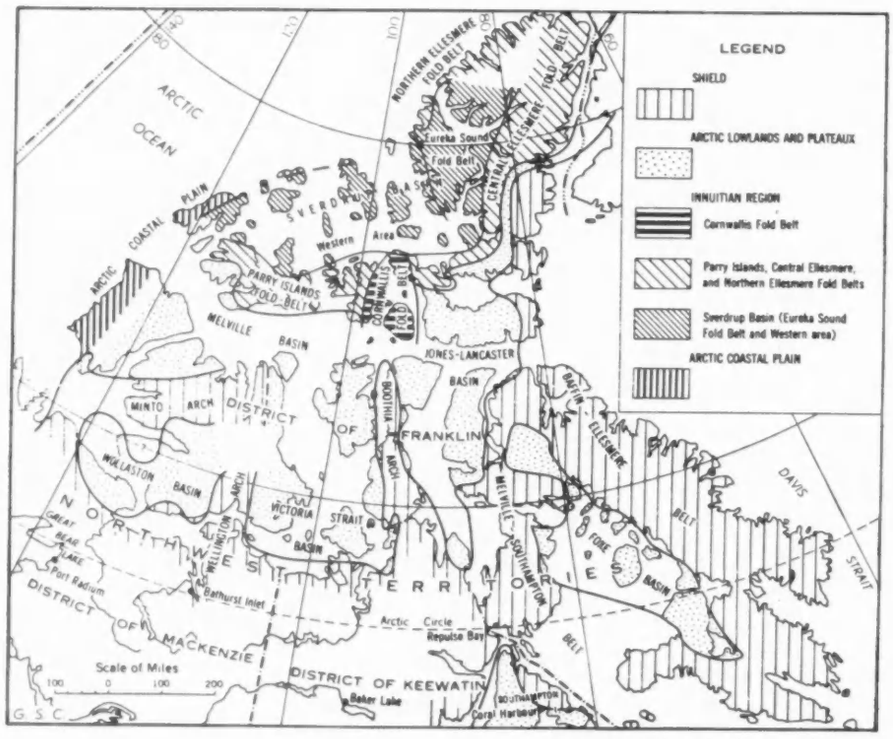
Innuitian Region. North of the Melville and Jones-Lancaster basins is the mobile Innuitian Region, which contains the Sverdrup Basin bordered by fold belts. The easterly-trending Parry Islands and the Central Ellesmere fold belts are roughly aligned and contain mainly Devonian rocks, but are interrupted by the northerly trending Cornwallis Fold Belt.

Ordovician and Silurian carbonates up to 20,000-feet thick occur in the Cornwallis belt, which may represent *a northern extension of the Boothia Arch.*

Cornwallis Island is essentially domal but is extensively faulted. Typical exposures of Ordovician and Silurian carbonates on Cornwallis Island are shown in Figure 3. Some of the porous dolomites in this vicinity are impregnated with bitumen.

Folds in the Parry Island belt trend easterly across Melville Island and most of Bathurst Island (Figure 4); are spaced at intervals of a few miles, and have amplitudes of several thousand feet. These folds plunge generally westward away from the Cornwallis belt.

The Devonian beds in the Parry Islands belt are marine carbonates and nonmarine clastics about 14,000 feet thick. These beds were folded during the Variscan orogeny prior to middle Pennsylvanian time, as shown by the unconformable overlap of Pennsylvanian and Permian sediments along the southern margin of the Sverdrup Basin. This overlap, as it is expressed on western Melville Island, is shown in Figure 5, with north-dipping Permian and Triassic beds resting unconformably on folded and eroded Pennsylvanian sandstones. The Pennsylvanian, in turn, lies unconformably on an older uninterrupted sequence of Devonian, Silurian and Ordovician. The Variscan orogeny thus is seen to endure at least two episodes, reminiscent of the dual char-



After Geological Survey of Canada

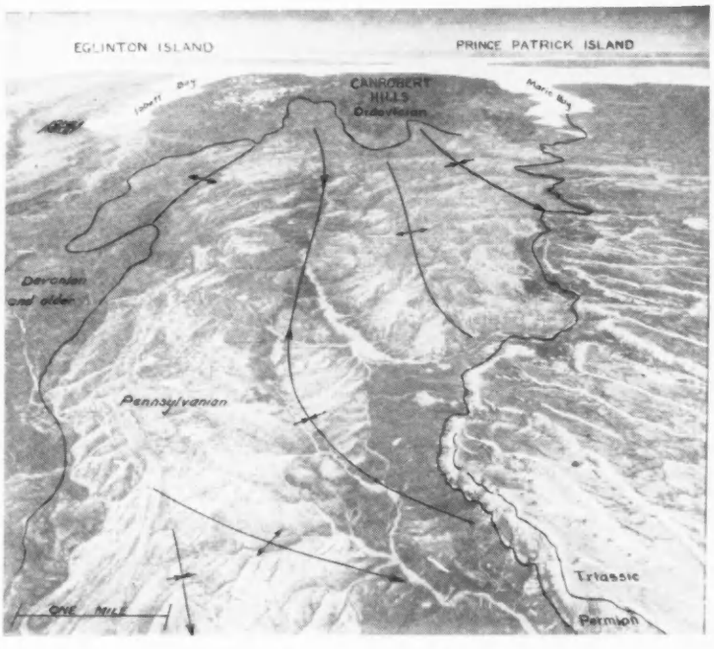
FIGURE 2—Mobile fold belts, trending both east-west and south-north are apparent in this map of geological regions and subdivisions of the Arctic Archipelago.

Royal Canadian Air Force photo

FIGURE 3—Ordovician and Silurian carbonates of Cornwallis Fold Belt are shown in this vertical air photograph of Resolute, Cornwallis Island. Some porous dolomites here contain bitumen. Indicated structural axes are from Geological Survey of Canada, Memoir 294.

Royal Canadian Air Force photo

FIGURE 4—This trimetrogon oblique looks eastward on Bathurst Island. Ordovician, Silurian, and Devonian sediments of the Parry Islands Fold Belt have been identified by D. J. McLaren, Geological Survey of Canada. Effects of Paleozoic orogenies are highly apparent on such aerial photographs of Arctic Islands.



Royal Canadian Air Force photo

FIGURE 5—Trimetrogon oblique looks westward from Melville Island. North-dipping Permian and Triassic strata rest unconformably on folded Pennsylvanian sandstones. Pennsylvanian is reported unconformable on older sequence. These photographs emphasize the ice-free nature of the drier Arctic islands in summer, and rapid delineation of surface geology.

Royal Canadian Air Force photo

FIGURE 6—Vertical air photograph of Isachsen Dome and vicinity, Ellef Ringnes Island, shows Cretaceous clastic sediments of Sverdrup Basin intruded by piercement of anhydrite and gypsum. More than 40 piercement domes have been mapped by Geological Survey of Canada.

acter of Pennsylvanian orogeny in the southern Mid-Continent region, which may be considered concurrent with that in the Arctic Islands.

Post-Paleozoic formations. The overlapping Permian beds are succeeded by the thick Mesozoic and Tertiary sequence of Sverdrup Basin. The mainly clastic sediments in the basin total as much as 33,000 feet in aggregate thickness. Typical Cretaceous exposures on Ellef Ringnes Island are shown in Figure 6. An interesting feature of the Sverdrup Basin is the occurrence of *piercement domes of anhydrite and gypsum* along its axis from northern Sabine Peninsula on Melville Island to Strand Fiord in western Axel Heiberg Island. Best known of these domes is Isachsen Dome (Figures 6 and 7) on Ellef Ringnes Island. More than 40 piercements have been mapped by the Geological Survey; they generally occur in the central portion of anticlinal folds.

Filling of the Sverdrup Basin culminated with deposition of at least 8,000 feet of nonmarine clastics of late Cretaceous and early Tertiary age. These beds were intensely deformed by the Alpian orogeny. Intrusive igneous activity is recorded by numerous basic dikes cutting Cretaceous beds in the central and eastern part of the Sverdrup Basin. The northwest margin of the Sverdrup Basin

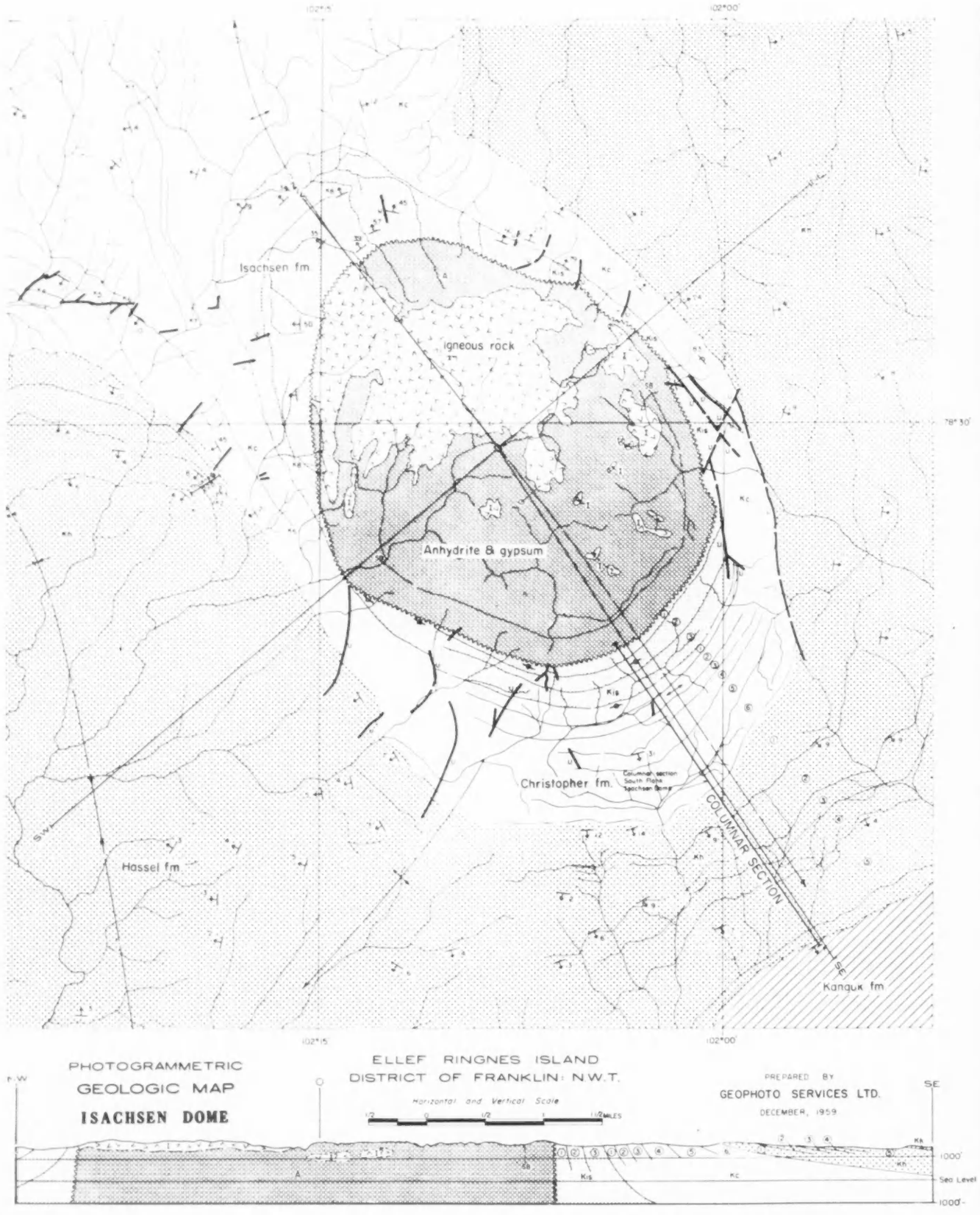


FIGURE 7—Photogrammetric geologic map and cross-section of Isachsen Dome (Figure 6) were prepared from aerial photographs.

is overlapped by nonmarine sands and gravels of the Cenozoic coastal plain, which extends southwestward along the west coast of Banks Island, where it overlaps the lower Paleozoic sediments of the Melville Basin.

PHOTOGEOLOGIC MAPPING

Identification of the formational units mapped in the Arctic Islands is facilitated by use of the preliminary geologic maps and reports of the Geological Survey.

About the Authors

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Dr. Don B. Gould is adminstrative geologist with Geophoto Services, Ltd., in Calgary. A native of Oklahoma, he received his B.S. degree in 1928 from the University of Oklahoma, and his M.S. and Ph.D. from the University of Iowa. After serving as professor of geology and chairman of the Geology Department at Colorado College, Gould carried on a consulting practice. In 1951, he joined Geophoto Services, served in various capacities in Denver and moved to Canada in 1958. Since then, he has worked mainly in the Yukon, Northwest Territories and Arctic islands.

Facies changes can readily be recognized in most parts of the Arctic Islands. Individual beds or thick sequences may pinch out when followed along strike, due to nondeposition or to erosional unconformity. The prominent angular unconformity along the southern margin of the Sverdrup Basin is evident on casual examination of the oblique photograph (Figure 5). Less pronounced discordances are readily seen in stereo-vision on vertical photography.

The Parry Islands Belt especially lends itself to facies analysis on air photographs, not only because of the clear expression of stratigraphic units which reveal variations in lithology as they are followed along flanks of eroded folds (Figure 4), but also because the parallel anticlines and synclines afford numerous repeitions of a given outcrop band in which the lithology can be compared in a direction transverse to the trend of the folding.

Although vertical control in the Arctic Islands is meager, numerous inlets provide a sea-level datum for use in levelling the three-dimensional model created by the plotting instrument.

WEATHER AND LOGISTICS

Weather conditions in the Arctic Islands are less extreme than in other areas far to the south. In July, the mean temperature at Resolute is about 40° F. Winter temperatures are not so rigorous as in the Yukon. Annual precipitation in the low-lying western islands averages about six inches. Although periods of fog are common, 24 hours of daylight permits round-the-clock operation when flying conditions are suitable. The cloudiness that builds up during late spring normally levels off in July, but over the western islands it reaches a maximum in August. Drilling operations are feasible throughout the year.

Government air routes serve the weather stations which have landing strips and an efficient system of radio communication. Landing aircraft at outlying points presents few problems; small aircraft equipped with oversize tires can land nearly anywhere. Operation Franklin employed two medium-size helicopters using fuel distributed by a ski-equipped two-engine transport airplane prior to deterioration of the sea ice.

Ice conditions limit marine transportation, but more powerful ice breakers are expected to alleviate this situation. Fuel and supplies for the use of field parties have been cached in advance in the past.

MAPS AND PHOTOGRAPHS

Topographic maps covering entire area are available from the Federal Government at Ottawa. These maps, at a scale of eight miles to one inch, show shore lines and major drainage features, but have sparse elevation data and are otherwise inadequate for detailed logistic planning. These maps were prepared from trimetrogon photography flown since World War II.

A program now in progress will provide complete vertical photo coverage of the entire archipelago at a scale of approximately one mile to one inch. This photography, when processed by photogrammetric instruments in combination with accurate horizontal control from sonar and electronic surveying measurements now being made, will permit construction of large-scale topographic maps. Part of the new vertical photography is available, mainly east of 108 degrees west longtitude. Both types of photography, vertical and trimetrogon, may be obtained from the National Air Photo Library in Ottawa.

The new vertical photography is being used in the preparation of base maps for photogeologic work. Due to the low topographic relief in most of the islands, photographic distortion is minimized and the change of scale between adjoining photographs is slight. This facilitates rapid and economical construction of accurate mosaics and base maps.

Preparation of an adequate field program in the Arctic Islands is a critical operation in which all available details of logistics and geology must be considered if wasted effort and incomplete results are to be avoided. Photogeologic mapping provides the ideal basis for selection of structures to be examined in the field and localities in which stratigraphic sections need to be measured and sampled to determine their source bed and reservoir characteristics.

A further step, and the really significant one in conserving precious man hours on outcrop, is structural and stratigraphic photogrammetry to produce structure contour maps and measured sections which will require a minimum of checking in the field and furnish the framework into which essential ground observations and samples can be keyed.

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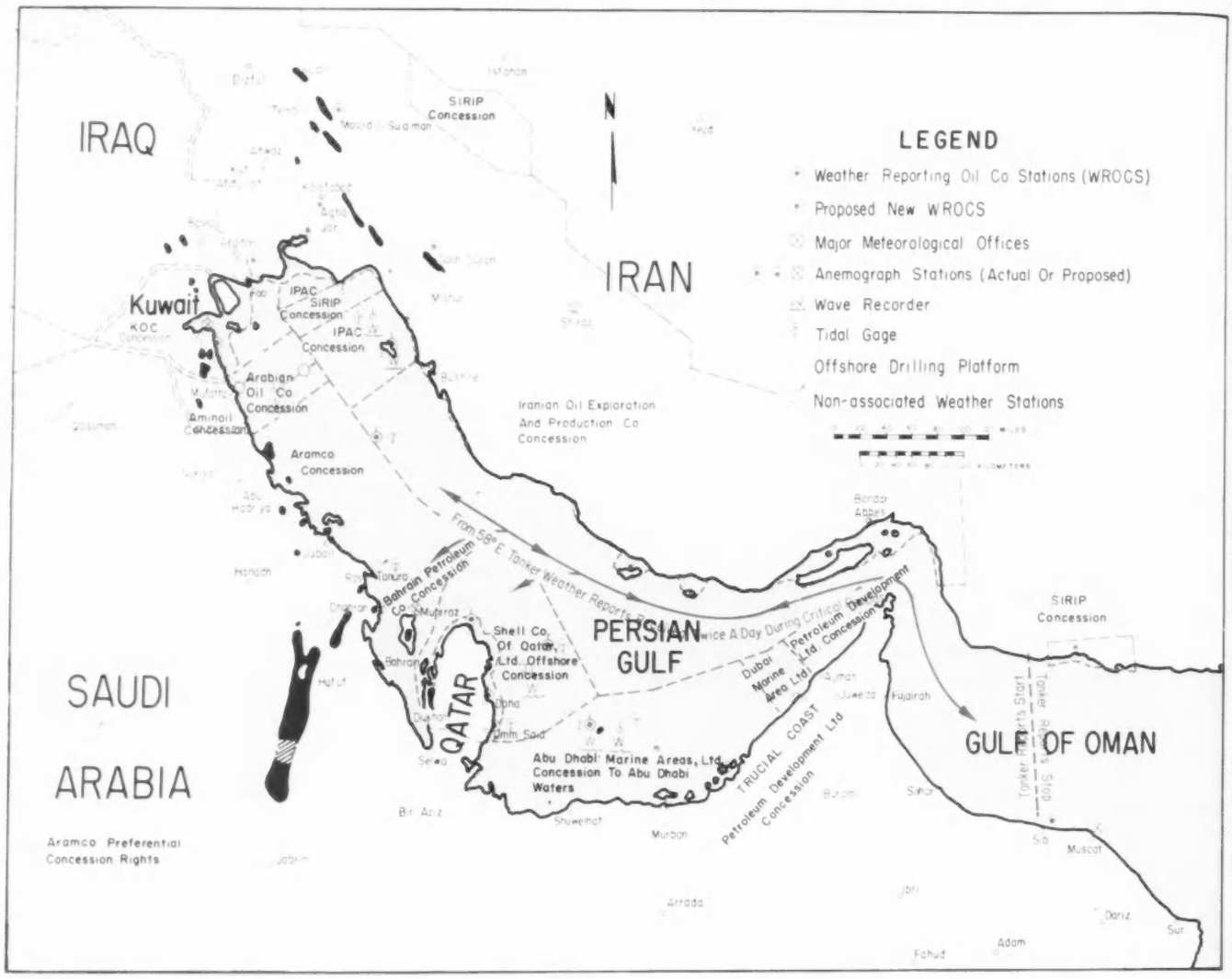

The Persian Gulf weather forecasting system is shown as it existed on November 13, 1959. There were 15 Weather Reporting Oil Company Stations (WROCS). Recently, new WROCS have been proposed for Shaikh Shu'Aib, Bandar Dailam, and Bandar Mashur. All WROCS are fully equipped for synoptic weather reporting for forecasting purposes. Several major state meteorological offices are included in the system, including a new one at Bandar Abbas. Most of the WROCS are equipped with anemographs which continuously record wind velocity and direction. Certain offshore installations have tide recording gages, and all the offshore drilling platforms have anemographs. Spot weather reports are received from tankers.

Persian Gulf weather forecasting system developing rapidly

Offshore drilling platform assembly and movement becoming much safer in treacherous Gulf waters

By David L. Hibbert, Managing Director, IMCOS Limited, London
T. F. Gaskell, Research Associate, The British Petroleum Company Limited, London

WHEN OFFSHORE DRILLING and production operations developed in the Persian Gulf, the need for a weather forecasting service soon became apparent. Although many successful movements of drilling barges took place without incident, the few accidents that did occur were so costly that the environmental factors of sea and wind could not be left to chance.

It was fortunate for the oil business

This is the Weather Reporting Oil Company Station (WROC) at Ras Rakan at the north tip of the Qatar Peninsula. The anemograph continuously records wind velocity and direction.

Tidal readings are an integral part of the Persian Gulf weather prediction system. This tide gage is located at Halul Island, between the Qatar Peninsula and Das Island.

that forecasters were available. They had been trained during the war years not only to make local assessments of the weather, but to apply the meteorological readings to the forecasting of sea and swell. The parallel researches of the Scripps Institute of Oceanography and of the British Navy had shown that the prediction of the height of sea waves was limited in accuracy only by the detail to which the pattern of wind pressure was known.

PERSIAN GULF

The paucity of regular weather observations in the Persian Gulf first became apparent some years ago when design data were required by engineers to construct drilling platforms to implement offshore exploration programs. Several independent groups of engineers attempted to determine the weather pattern by examining old records, but the material available was limited to a few Royal Air Force stations and port authorities. This information was adequate in the construction stages, but it was inadequate for the tricky maneuvers called for in setting up drilling platforms.

The need for a comprehensive weather forecasting system in the Persian Gulf was emphasized spectacularly in December 1956. During the crucial stage of dissassembling a drilling platform, a sudden change in wave direction caused it to be wrecked. The drilling outfit was being operated by Shell Company of Qatar, Ltd. (see WORLD OIL, August 15, 1957, Page 260).

The early movements of the Shell platform had to rely on almost nonexistent meteorological coverage.

The planners of the Abu Dhabi Marine Areas project envisaged the need for an experienced meteorologist to advise the setting up of their first platform. But undoubtedly the loss of the Shell Exploration platform in 1956 brought home to all concerned the essential need for a proper meteorological service.

The firm of IMCOS Ltd. was engaged to do the specialist marine forecasting work, and as a necessary preliminary to advise on setting up reporting stations. Both Shell Exploration and the Qatar Petroleum Company agreed to help, by reporting to Das Island from weather stations established in the Qatar peninsula and at Halul Island.

This first joint reporting system worked very well. Since further use was envisaged for it in the future, it was agreed that the reporting stations should be kept going all the time.

Out of this southern group of cooperating companies has grown the complete network of WROCS (Weather Reporting Oil Company Stations) covering the whole Persian Gulf area. Through a Joint Oil Company Meteorological Committee, all WROCS come under the advisory direction of IMCOS Ltd.

As of November 1959, eight oil companies operating in the Persian Gulf area were members of the Joint Oil Company Meteorological Committee. They were Kuwait Oil Company, Qatar Petroleum Company, National Iranian Oil Company, AGIP-Mineraria, Iran Pan American Oil Company, Iranian Oil Explora-

tion and Producing Company, Shell Tankers Ltd., and BP Exploration Company.

Instruments and weather observing and reporting procedures are standardized as far as possible, and copies of records are sent every month to IMCOS Ltd. in London, where they form a collection of past weather data available to all participants.

WROCS network. The map shows the positions of reporting stations. Advantage has been taken of oil fields, exploration camps, air-strips and marine installations used by the various oil companies participating in the scheme. Those locations already possess the necessary communications facilities and personnel to conduct weather observation and reporting. Tanker weather reports from selected ships form a valuable supplement to the fixed stations when required.

For communications purposes, the Gulf has been divided into two zones. Stations in the northern zone report to Masjid-i-Sulaiman, and those in the south to Das Island. These two centers exchange by special radio broadcast the "collective" message each has made of its zonal observations. From either station the forecaster can receive and plot the weather from all WROCS from Masjid-i-Sulaiman in the north to Muscat in the southeast; from stations at airstrips such as Gach Saran, at marine offices as at Ahmadi, on artificial islands such as the "Enterprise," and on desert islands such as Farsi and Halul. This network is fundamental to the weather services now being given to the oil industry in the Gulf.

The weather network was established primarily to minimize hazards of offshore exploration involving movable floating platforms. The service it makes possible is equally applicable to other operations, such as deep-water terminal construction and underwater pipe laying. At loading terminals, as at Kuwait and Kharg Island, the forecasting of conditions likely to stop loading may become an important duty.

But forecasting for all operations in the Gulf cannot be done from a central forecast headquarters. Even if this were feasible it is doubtful if it is desirable. The weather network has been designed to meet the requirements of IMCOS mobile forecasting units operating wherever required on the site of, and for the duration of, whatever critical operation is in hand.

When such an operation is about to start and forecasts are needed, a critical period is declared, and the WROCS network is geared to feed all information into the temporary weather forecast headquarters. An "all ships" wireless message, referring to a Standing Order, alerts all British Petroleum and Shell tankers to a twice-a-day weather reporting schedule, which they adhere to while in the Gulf area. Information from the regions outside the WROCS network is called for from the nearest State Meteorological Office.

In daily or hourly consultation with the project manager, the forecaster on the spot advises on the weather and probable sea conditions of 12 to 24 hours ahead, pinpointing the forecast for the location and interpreting it in terms of the operation.

Weather outlooks covering up to three days may be asked for when there is a long sea tow before a drilling platform can be jacked up on location. In such a situation it is vital that the operator appreciates the sometimes almost tenuous considerations which go to making up a medium range forecast and determining their confidence "rating," ratings which will vary considerably with the season and current weather pattern.

Since the WROCS system was introduced by IMCOS at the end of 1957, the network has been alerted for four mobile drilling platform operations, all successfully completed.

With the development of the WROCS network, consistent records of the weather over the whole of the Gulf are accumulating, and with knowledge of what exactly is going on will come understanding of phenomena which seem peculiar to the Gulf. The characteristic fluctuation of the summer shamal wind may yet be satisfactorily explained and forecast, as may the winter storms.

An extensive program of wind and wave measurement is being carried out. It will offer an unrivaled opportunity for the study of wind-wave relationships. Much of what is learned will have application far beyond the Persian Gulf. Wave recorders on mobile drilling platforms, such as the Adma "Enterprise," the Shell "Seashell" and those operated by IPAC, SIRIP, and Arabian Oil Company, will help to solve some long-standing oceanographic problems as well as provide the forecaster with valuable information for immediate application. The ramifications of the oil companies' weather work spread into every activity, oil and non-oil, in the Gulf.

But this mutually supporting weather system is organized primarily for oil men, by oil men. They appreciate that while control of the weather is a long way off, its effects can be minimized by designing and planning against known odds, working with the weather rather than against it. —**The End**

About the Authors

Hibbert

Gaskell

David L. Hibbert since 1952 has been managing director of IMCOS Limited (International Meterological Consultant Service), a commercial weather consulting organization with headquarters in London. During World War II he was in military service as a meteorologist, specializing in aviation aspects of weather problems.

Dr. T. F. Gaskell is research associate of the Exploration and Production Department of The British Petroleum Company Limited. After graduation from Cambridge with honors in natural sciences in 1937, he conducted research there in geophysics until World War II.

His war years were spent with the British Admiralty in anti-submarine work and later in beach reconnaissance and wave forecasting.

After three years as Chief Petroleum Physicist for Anglo-Iranian Oil Company (now The British Petroleum Company, Ltd.), in 1949 Gaskell joined the *HMS Challenger* oceanographic expedition as Chief Scientist. This expedition made seismic and deep sounding measurements in oceans in many parts of the world, over a 2½-year period.

PART 3 – A STEP-BY-STEP PROCEDURE

How to control blowouts

Handling kicks during a trip requires close watch of mud gel strength, effects of swabbing, keeping hole filled and changes in mud pit volume

By T. B. O'Brien, Head, Drilling Section, Technical Services, Gulf Oil Corporation, Houston

W. C. Goins, Jr., Section Head, Drilling Research Gulf Research and Development Company, Harmarville, Pa.

This third and final installment continues the detailed outlining of steps to be taken in understanding, watching for and coping with threatened blowouts. Parts 1 and 2 appeared in the May and June issues, respectively.

Among the topics covered here are:

- Techniques for controlling kicks while making a trip.
- Reasons for maintaining proper gel strength in mud.
- Problems relating to and methods of preventing swabbing while coming out of the hole.
- Importance of and techniques used in keeping hole filled.
- Need for closely watching pit volume.
- How to strip drill pipe through a bag-type blowout preventer when stripping back into the hole.
- Arguments, pro and con, for using reverse circulation when a well kicks.

KICKS WHILE MAKING A TRIP

It is variously estimated[5] that from 50 to 70 percent of all blowouts occur while making a trip. Strangely enough, most efforts have been directed toward killing the much less frequently occurring kick while drilling is in progress. The period under consideration is from the time drilling ceases and the bit is pulled off bottom until it is back on bottom and drilling resumes. It must be assumed that the drilling fluid in use at the time drilling stopped had sufficient density to at least slightly overbalance the formation pressure. This being the case, only two things can cause the well to flow—either the well is swabbed as the drill pipe is pulled or the crew fails to fill the hole.

Consider the first case. It can have a number of causes. Mud with excessive gel strength is often the cause of swabbing. Cannon,[6] in 1934, showed this to be the case. Since that time there has been a considerable reduction in measured gel properties of drilling muds in areas most subject to swabbing difficulties. However, there are still quite a number of muds used in many areas of the world that run high viscosities and attempt to run low gel strengths. Some muds are purposely still run with high gel strengths. Regardless of any other consideration this is a dangerous procedure.

Gel strength critical. Very often the muds which have low measured gel strengths, even at the 10-minute measurement at ambient temperature, actually develop substantially higher gels at bottom-hole temperature in the time required to make a trip. This is the case in most of the more conventional muds, i.e., red muds, lime muds, phosphate muds, etc. It is highly probable that this type of gel may be much more dangerous than that which builds rapidly and is characterized by almost equal initial and 10-minute gels. The first type is known as a slow gel, the second as a flat gel.[7]

This is not intended as a recommendation against the use of the types of mud mentioned above. Rather it recommends that when these muds are being run, the solids content be run at the lowest practical level, and particular care be given to the maintenance of minimum gel

strengths and gel rates. It also is necessary to be somewhat more careful when making a trip to be certain that no swabbing occurs.

Although not as critical as gel strength, viscosity also can be a serious factor in swabbing. Viscosity being the resistance of fluid to flow, there is a tendency for the mud column to rise with the drill pipe as it is pulled, creating a reduction in bottomhole pressure. This tendency to move with the drill pipe increases as the viscosity increases. At very high viscosity the drop in bottomhole pressure will be appreciable, causing formation fluid to flow into the bore hole.

The foregoing two conditions, when coupled with small annular clearance, will very regularly produce swabbing. These conditions occur in almost every deep well that utilizes a high-weight mud, and in shallow slim-hole drilling with mud only slightly heavier than water. Little can be done as a rule to increase annular clearance, but mud properties can be arranged to reduce to a minimum the possibility of swabbing.

Hazards of swabbing. The detection of swabbing is often most difficult, and it is for that reason that so many blowouts occur while a trip is being made. The difficulty in detecting swabbing results from the fact that, although the hole takes some mud when it is filled, it does not take all it should.

Comparatively few drilling rigs have any method of accurately measuring the volume of mud in the active pit or the volume of mud pumped into the hole. A driller may use several methods for adding mud to the annulus, if he fills it at all. He may run a pump on the fill-up line continuously or he may at intervals fill the hole until it runs over; or, if the drill pipe will not pull dry with the hole full, he may put just a small amount of mud in the hole at intervals. In no case can he tell how much mud he has put into the hole.

Swabbing could occur and in some cases it would not be known until the well was flowing at a tremendous rate or unless the driller happened to look when the pit ran over. Furthermore, the initial effects of swabbing are so slight that quite accurate measurements of mud volume are required if swabbing is to be detected in its early stages. Table 4 gives the displacement of the more common sizes and weights of drill pipe. It can also be used for accurate measurement of the volume required to fill the hole while making a trip.

Table 5 gives the amount of mud gained when drill pipe is pulled from the hole and when varying percentages of the drill pipe displacement are swabbed in. At 100-percent swabbing, the hole would stand full as the drill pipe is pulled. It would take no mud but none would be gained. Percentages less than 100 indicate that fraction of the drill pipe displacement which the hole does not take as the pipe is pulled. On occasion, swabbing goes beyond the point of the hole standing full. In fact, the entire hole volume may be swabbed as by a balled-up bit or a dragging packer. This sort of thing should be obvious and no special methods are required for its detection. Under no circumstances should it be allowed to occur.

The insidious nature of swabbing is illustrated by the small volume of mud involved when a hole does not take all the mud it should. It is apparent that most swabbing cannot be detected by the usual method of checking the pit level. We very often lose more mud than indicated here by pulling a few wet stands. In most such cases swabbing is indicated by gas- or water-cut mud after a trip. In these instances swabbing occurs for a few stands then after the bit is up the hole for a short distance, the hole takes all the mud it should.

Occasionally swabbing is not detected and it continues as the bit or other tools are pulled. The 20-to-60 psi loss in bottomhole pressure becomes 200 to 600 psi, and before pipe is back in the hole, the bottomhole pressure has been reduced to the extent that the well flows a noticeable volume of mud. With higher mud weights and deeper wells, this loss in pressure becomes greater.

This further indicates the value of a small active mud pit. The primary concern, however, is that an accurate determination be made of the amount of mud used to fill the hole each time. Of course, displacement of the drill pipe being pulled should be known. With these two, the driller can be certain of his position at all times and will know immediately if the well starts to follow him out of the hole.

Keep hole filled. Another practice which has been followed, but which should be almost out of existence now, is that of not filling the hole at all. For this there is no excuse. A well being drilled with a fluid other than air or gas should be filled as the pipe is pulled from the hole. To fail to do this is gross neglect. Nothing can be gained by not filling the hole, and everything could very easily be lost.

Further, too long an interval should not be allowed between the times the hole is filled. Experience in an area generally indicates a reasonable procedure, but unless conditions are such that swabbing can easily occur, the hole can be filled once each 10 stands for 8⅝-in. holes and larger, and once each five stands for holes smaller than 8⅝-inch. If swabbing is known to be a problem, the hole should be filled after each stand or possibly each second stand.

An indication of how often swabbing occurs is the frequency of the appearance of trip gas or water-cut mud after a trip. Very often it is the practice to increase mud density to eliminate trip gas, but this is a poor subsitute for good operating procedure and should be used only as a last resort. It is far better to eliminate the causes of swabbing than to increase mud density and risk loss of circulation, in addition to suffering from a slower drilling rate.

Should improvement of mud properties, careful handling of the drill string, and accurate measurement of mud used to fill the hole fail to stop swabbing, there is still another approach. The drill pipe can be stripped out of the hole. A drill-pipe float is not essential for this operation but it would be helpful.

The preventer is closed lightly around the drill pipe; and as each stand is pulled, the displacement of that stand is pumped into the annulus. This must be done very carefully, avoiding the application of excess pressure to the open hole. If this method is not practical, as it will not be on many rigs, the pump can be run on the annulus and on one or more guns or chokes, to maintain a back pressure on the annulus.

Some method of very accurately determining, at frequent intervals, the volume pumped into the hole is required. Usually, cutting off one pit from the remainder of the system will provide a sufficiently accurate tank for measuring mud volume. In a very critical situation an even smaller tank having a capacity 10 to 20 barrels, calibrated in 1-barrel increments, will serve very well. This method is known to have been applied in several cases with considerable success. It must be emphasized that it should be used with understanding if the operator is to stay out of trouble.

Since it is understood there always will be operators who consider a haphazard approach to the problem of blowout prevention to be a calculated risk, it is reasonable to assume that some contractors who work for them will not properly train their crews to prevent blowouts. Therefore, one can expect the application of something less than the best principles in handling situations which might lead to blowouts. It follows, then, that some thought should be given to what to do when the well follows the bit out of the hole.

Return bit to bottom. As in any other situation, early detection is desirable but can hardly be expected. One probably can expect the crew to realize the well is coming in when it flows of its own accord. The idea will be to get the well killed with the least damage to the hole. To do this the drill pipe must be as close to bottom as possible, because the nearer the bit is to bottom, the less mud weight is required to kill the well. Indeed, if the bit can be returned to bottom, no increase in mud density will be required.

The following will illustrate the desirability of returning the pipe to bottom or as near to bottom as possible. Consider this example:

A well is drilling at 15,000 ft with 15 ppg mud. As the bit is pulled to 10,000 ft, it is discovered that the well is coming in. By percentage of total hole volume swabbed, mud weight requirements at 10,000, 11,000, 12,000, 13,000, 14,000 and 15,000 ft are given in Table 3. (See Part 1, May Issue.) A sample calculation is given here.

At 10,000 feet, 10 percent hole volume swabbed

$$\begin{aligned} \text{So, } 15{,}000 \times 0.052 \times 15 &= \text{original bhp mud} = 11{,}700 \text{ psi} \\ 10{,}000 \times 0.052 \times 15 &= 7{,}800 \\ 5{,}000 \times 0.052 \times 15 \times 0.90 &= 3{,}500 \\ & \underline{11{,}300} \quad \underline{11{,}300} \\ & \qquad 400 \text{ psi bhp lost} \end{aligned}$$

$7{,}800 + 400 = 8{,}200$ psi bhp_m at 10,000 feet required to kill well

$$\frac{8{,}200}{0.052 \times 10{,}000} = 15.8 \text{ ppg mud weight required to kill well at 10,000 feet if 10 percent of hole volume swabbed}$$

Table 3 shows that the higher the percentage swabbed, the more critical becomes the return to bottom. Also illustrated is that effect which causes gas cutting on trips. The figures given for mud weight are those which are required to balance the formation pressure. Usually, wells are drilled using at least a 500 psi overbalance at depths below 10,000 feet. Often this overbalance is equal to or greater than 1,000 psi, although as much as 25 percent

TABLE 4—Drill Pipe Displacement

SIZE INCHES O.D.	Designation	Nominal Weight Lb. Ft.	Average Actual Weight Lb. Ft.	DISPLACEMENT—BARRELS Bbl./Ft.	1-90′ Stand	5-90′ Stands	10-90′ Stands
2⅜	Tubing T & C	4.70	4.59	.00167	.15	.75	1.50
	Tubing T J	4.70	5.13	.00187	.17	.84	1.68
2⅞	Tubing T & C	6.50	6.34	.00233	.21	1.05	2.11
	Tubing T J	6.50	7.22	.00263	.24	1.18	2.37
	LWDP	6.85	7.33	.00267	.24	1.20	2.40
	Drill Pipe	10.40	10.90	.00397	.36	1.79	3.57
3½	Tubing T & C	9.50	9.20	.00335	.30	1.51	3.02
	Tubing T J	9.50	10.13	.00369	.33	1.66	3.32
	LWDP	9.50	10.27	.00374	.34	1.68	3.37
	Drill Pipe	9.50	10.27	.00374	.34	1.68	3.37
	Drill Pipe	13.30	13.80	.00503	.45	2.26	4.53
		15.50	16.1	.00587	.53	2.64	5.28
4½	Tubing T & C	12.75	12.83	.00467	.42	2.10	4.20
	Tubing T J	12.75	14.58	.00531	.48	2.39	4.78
	LWDP	13.75	15.08	.00549	.49	2.47	4.94
	Drill Pipe	16.60	17.80	.00648	.58	2.92	5.83
	Drill Pipe	20.00	21.60	.00776	.70	3.49	6.98
5	LWDP	15.00	17.69	.00644	.58	2.90	5.80
	Drill Pipe	19.50	20.60	.00750	.68	3.38	6.75

NOMENCLATURE

Tubing T & C—Tubing with threads and couplings.
Tubing T J —Tubing with tool joints.
LWDP —Lightweight drill pipe.

TABLE 5—Volume Gained Due to Swabbing

Drill Pipe O.D.	Nominal Wt. Ft.	DISPLACEMENT 1st Std.	DISPLACEMENT 10 Stds.	VOLUME GAINED* 10 Percent	25 Percent	50 Percent	100 Percent	BHP REDUCTION (psi) WHEN 10 STANDS PULLED-10 PPG MUD Hole Size	10 Percent	25 Percent	50 Percent	100 Percent
2⅞″	10.40	.357	3.57	.036	.089	.178	.360	5⅝″	6	15	30	60
3½″	13.30	.453	4.53	.045	.112	.224	.450	6″	6.7	17	34	67
4″	16.60	.583	5.83	.058	.145	.290	.580	8⅝″	4.2	11	21	42
5″	19.50	.675	6.75	.068	.169	.338	.675	9⅞″	3.2	8	16	32
								9⅞″	3.5	9	18	35
								12¼″	2.3	6	11	23

* Volume gained when 10 stands pulled and indicated percentage swabbing occurs.
Volume = inches in pit having capacity of 10 barrels per inch.

swabbing occurs for the first 5,000 ft off bottom (as shown here) and the well will not flow.

However, when the bit returns to bottom and the gas or water that has been swabbed is circulated out, gas or water-cut returns are noted. If the foreign fluid is gas, or water and gas, one can expect a considerable kick when it reaches the surface. Some further reduction in bottom-hole pressure can be expected, but it will be fairly small if the well did not flow when the bit was returned to bottom and before the pump was started. The method of control will be quite similar to that given for the control of a kick while drilling. In this case several things will make control easier. First, no increase in mud density is required, and second, the circulating rate and pressure are established. No change need be made in the circulating rate, but careful control of circulating pressure is required.

Watch pit volume. When circulating off bottom until returns are up a close watch should be kept on the pit volume. This, of course, is particularly true if any mud has been gained while making the trip. Some gain in the pit is always to be expected as swabbed fluid is circulated up. This means a further reduction in bottom-hole pressure is occurring.

Since it is very rarely known how much overbalance pressure is present for safety, it is necessary to assume that this expansion of foreign fluid causes the loss of all the overbalance which might have existed. The only pressure available over hydrostatic pressure of the mud is the annular pressure drop resulting from circulating. This may be equal to from 0.1 to 0.4 ppg mud weight. It might hold a well that was swabbed, as indicated in Table 3; i.e., 5 percent for 5,000 feet. In most instances it will not by itself control a flow if the over-balance has been lost.

If the assumption is made that the overbalance is lost, then it becomes necessary to close the blowout preventers and put the well on a choke to maintain sufficient back pressure. The back pressure required is determined by the drill pipe pressure rather than casing pressure. In this case the well should be choked just enough to give an indication on the drill pipe gage.

A choke may not be required. Instead, an open line may suffice if the circulating rate is high enough. When the foreign fluid reaches the surface, the annular pressure will start to fall and a larger opening will be required. Size of the opening to be selected for the annulus always will be that which is needed to keep drill pipe pressure constant.

The well must not be allowed to flow any more than what is absolutely necessary. To prevent the well flowing, a back-pressure valve (inside blowout preventer) should be installed in the drill pipe and the drill pipe stripped back in the hole through the bag-type preventer as far as possible. During this stripping operation it is essential that the preventer be allowed to leak a very small amount as the pipe moves through it to provide lubrication for its seal subber.

If some means of filling the drill pipe is available as it is stripped in, it should be done. In many cases it will not be absolutely necessary; but in some cases the depth to which the pipe can be run will be determined by its collapse resistance (see Table 6). The depth to which pipe can be run without filling can be determined by the following formula:

$$\frac{\text{Collapse strength, psi}}{0.052 \times \text{mud weight, ppg}} = \text{setting depth, feet}$$

For example (1): 3½-in. OD 13.30 lb. per ft. Grade D

Setting depth 9,170 ft.
Mud weight 10.0 ppg

$$\frac{9{,}170}{0.052 \times 10} = 17{,}600 \text{ ft,}$$ depth to which 13.30-lb Grade D 3½-in. drill pipe will run in 10 ppg mud without filling.

Example (2): Same situation except 17.5 ppg mud.

$$\frac{9{,}170}{0.052 \times 17.5} = 10{,}100 \text{ ft,}$$ depth to which 13.30-lb Grade D 3½-in drill pipe can be run without filling.

If the drill pipe is old, a safety factor of 1⅛ should be used. This would make the formula:

$$\frac{\text{Collapse strength, psi}}{0.0585 \times \text{mud weight, ppg}} = \text{Setting depth}$$

Example (2), above, then would become:

$$\frac{9{,}170}{0.0585 \times 17.5} = 9{,}000 \text{ ft,}$$ depth to which 13.30-lb Grade D 3½-in. drill pipe can be run without filling.

Another limit on the depth to which pipe can be stripped in the hole is the pressure which builds up in the annulus. This limit can be applied in two ways: (1) by the ability of the formations drilled to support the pressure, in addition to the pressure exerted by the mud left in the hole; and (2) the ability of the blowout preventer to withstand the pressure.* Should any of these limits be reached, or a bridge be encountered before the bit gets to bottom, it will be necesary to increase the mud weight over that used while drilling to kill the well.

The extent to which the mud weight will have to be increased can be determined after the drill pipe has been filled with mud and cleared of air by determining the pressure required to open the back-pressure valve. The determination of this mud-weight increase is of the utmost importance. It will allow for adequate mud pressure

TABLE 6—Strength of Drill Pipe and Drill Tubing

Drill Pipe O.D.	Weight (Lbs./Ft.)	Grade	Burst	Collapse	Tensile
2⅜"	4.70	N-80	11,200	9,380	104,340
	4.85	E	10,580	8,830	97,820
	6.65	D	11,350	10,140	101,000
	6.65	E	15,470	12,480	138,000
2⅞"	6.50	N-80	10,570	8,900	144,960
	6.85	E	9,980	8,830	135,900
	10.40	D	12,120	10,730	157,000
	10.40	E	16,530	13,210	214,000
3½"	9.30	N-80	10,160	8,580	207,220
	9.50	E	9,600	8,080	194,270
	13.30	D	10,120	9,170	199,000
	13.30	E	12,350	11,290	272,000
4"	11.00	N-80	9,170	7,520	246,140
	11.85	E	8,660	7,080	230,760
	14.00	D	7,940	7,380	209,000
	14.00	E	10,830	9,090	285,000
4½"	12.75	N-80	8,440	6,680	288,040
	13.75	E	7,900	6,290	270,030
	16.60	D	7,210	6,760	242,000
	16.60	E	9,830	8,310	331,000
5"	15.0	E	7,830	6,140	328,070
	19.50	D	6,960	6,550	290,000
	19.50	E	9,500	8,060	390,000

* It must be remembered that drill pipe stripped in the hole displaces a considerable volume of mud, and this should be bled off to prevent the buildup of excess annular pressure.

to kill the well without undue possibility of breaking down the formation with excess mud weight.

The method for determining the mud weight required and the method to be used for controlling drill pipe and annular pressures will be the same as those proposed in the section on "Killing a Threatened Blowout While Drilling."

It has been assumed that the well would start to flow as the pipe is being pulled from the hole, but the same principles will apply to any other time the bit is off bottom. The thing to do in any case is to get the pipe as close to bottom as possible and allow no more foreign fluid to enter the hole.

REVERSE CIRCULATION POSSIBILITIES

When a well kicks—and if it is closed in immediately—the best method of overcoming the kick from the point of view of pressure control is to reverse out the formation fluid that has entered. Several obvious advantages are to be gained. The initial closed-in pressure would be the highest to which the casing and blowout preventers would be subjected. Pressures would be confined to a small area which can be closed off by a simple valve above the rig floor. All chokes and other auxiliary equipment easily could be mounted above the floor.

Possibly other advantages could be gained, but several disavantages make circulation in the usual manner far more desirable. First, the application of pressure to the annulus of a drilling well is always a critical operation. The slightest excess can and often does cause lost circulation. In normal circulation, because a very high percentage of the circulating pressure drop occurs in the drill pipe, most of any variation in pump pressure would be absorbed in the drill pipe rather than in the annulus.

If the kick is to be controlled in something other than a haphazard fashion, it is necessary to know what the conditions are in either the drill pipe or annulus at all times. With reverse circulation and the present methods for determining the initial rate and period of inflow of formation fluids this is impossible. Some fairly close approximations may be made, but without actual field trial it cannot be said whether they would be close enough.

As soon as reverse circulation begins, the mud in both the drill pipe and annulus is cut by the foreign fluid; and from that point on it would be quite difficult to determine the pressures that should be maintained at the surface to properly control the bottom-hole pressure. Although the annulus pressure eventually might be reduced to the initial drill pipe pressure, no means of determining the conditions in the drill pipe are available. This is true because the height filled by the cut mud inside the drill pipe is considerably different from that to which it filled in the annular space.

A second effect that could result from the difference in area of the annular space and drill pipe is that if a fairly large volume (100 to 200 barrels) of mud were gained, the entire drill pipe could become filled with formation fluid; and pressures almost equal to formation pressure would have to be contained by surface equipment.

To be able to reverse circulate at all, a sub having large-size circulating ports which could be opened must be run just above the bit. Such a sub necessarily would be a limber section of the drill collar string, and would be weak as compared to normal subs or drill collars.

Regardless of the size ports used in the sub, it would be possible for them to become at least partially plugged. Should the port become partially plugged, additional pressure would be applied to the annulus, thus increasing the possibility of a formation breakdown up the hole. Complete plugging almost would certainly cause a formation breakdown. Further, should plugging occur, circulation in the normal direction probably would be impossible because of formation chips, too large to pass bit jets, entering the drill pipe through the sub ports.

It may be said, therefore, that with present equipment and know-how, reverse circulation offers far more disadvantages and hazards than advantages.

PROCEDURE FOR KILLING BLOWOUTS

In summary, when a gain in volume is noted the following procedure should be followed:

1. Stop pumps and close well in completely. If off bottom, install back-pressure valve and return to bottom.

2. Read drill pipe and annulus pressures.

3. Open well on choke of such size that, with the pump running at a reasonable and constant speed, the choke pressure will be about 200 psi above the initial annulus pressure.

4. From this time keep the drill pipe pressure constant, making changes in choke size as necessary to keep the drill pipe pressure constant. The choke pressure can be ignored unless it gets high enough to burst the casing; then, and only then, should the choke be increased to relieve the choke pressure.

5. Mud weight required to kill the well should be calculated, using the formula provided. As the mud weight is increased, corrections should be made in the drill pipe pressure. The drill pipe pressure will decrease as the mud weight is increased. When the mud weight has been raised to that required, the drill pipe pressure should be that normally required to circulate at the pumping rate used.

Formula to determine required mud weight:

$$\text{Mud weight required} = \text{mud in use} + \frac{\text{drill-pipe pressure}}{0.052 \times \text{depth}}$$

This article from "The Mechanics of Blowouts and How to Control Them" by T. B. O'Brien, Gulf Oil Corporation and W. C. Goins, Jr., Gulf Research and Development Company, presented at Southern District Spring Meeting, Division of Production, API, San Antonio, Texas, March 16-18, 1960.

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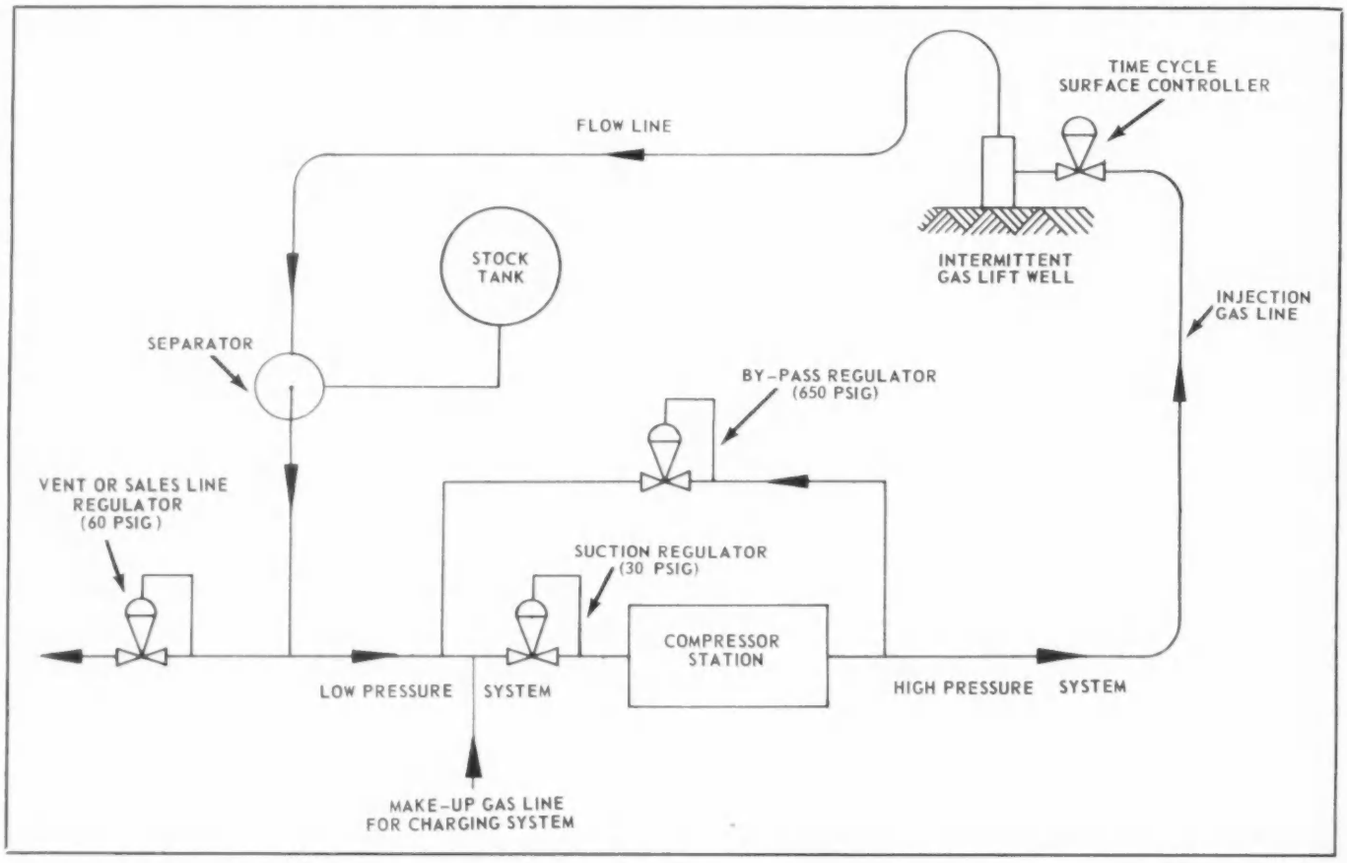

FIGURE 1—Simplified flow diagram of a closed rotative gas lift system for single intermittent well.

PART 1: Procedure

How to design a closed rotative gas lift system

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A CLOSED ROTATIVE gas lift system for a single well is shown in Figure 1. The installation is termed a closed system because the total gas-out from the well (formation and lift) is returned to the suction of the compressor for compressing and gas lifting the well.

After a closed rotative system is initially charged, the only make-up gas of any significance is the fuel requirement for the compressor prime mover, provided no gas is vented, sold, or used for lease operation. Generally, formation gas from the wells is more than adequate for supplying the fuel requirement. A closed rotative gas lift system has the advantages of a central power plant, and these advantages increase with an increase in the number of wells in the system.

If all wells to be gas lifted are in the continuous flow category, design of the closed rotative gas lift system presents no problem. The gas required to lift the wells represents a constant demand from the compressor station, and the total gas returning from the wells also is nearly constant. However, actual closed rotative systems generally are not this simple because a few, if not all wells, may be in the intermittent category.

If time cycle surface controllers are used on the injection gas lines to the intermittent wells, a large volume of injection gas is required for short periods of time and no injection gas is needed between periods of gas injection. Consequently, the compressor output must be capable of supplying this high per-minute requirement while

the surface controller on the injection gas line is open, or the additional injection gas in excess of the compressor output must be obtained from the high pressure injection gas system. Generally, the cost of an adequately designed high pressure injection gas system is less than the cost of additional compressor horsepower required to deliver the per-minute intermittent gas requirement.

Many intermittent installations are designed to lift with a continuous injection of gas into the casing, thus eliminating the high per-minute requirement for short periods of time followed by long intervals when no gas is required. Regardless of how the injection gas is introduced into the well, the lift plus formation gas returns to the low pressure gas gathering system at a relatively high rate following surfacing of the liquid slugs.

The low pressure system should be designed to hold the fluctuating gas volumes produced from the wells. If too much gas leaves the low pressure system after the liquid slugs surface, make-up gas must be supplied from an outside source. If make-up gas is costly, low pressure system design is important.

This article illustrates procedures and calculations required for designing a closed rotative gas lift system which requires capacity in the high pressure injection gas and low pressure gas gathering systems. These calculations are divided into the following parts:

1. Estimation of daily injection gas requirement for assumed injection gas pressure
2. Calculation of approximate compressor brake horsepower
3. Design of the high pressure injection gas system
4. Calculation of excess or make-up gas volume
5. Design of the low pressure gas gathering system.

DESIGN CALCULATIONS

Estimation of daily injection gas requirement for assumed injection gas pressure. The injection gas requirement is a function of the injection gas pressure available to lift the well, and the wellhead tubing pressure. The injection gas pressure selected should be adequate to efficiently lift the well to depletion.

The wellhead tubing pressure used to calculate the injection gas requirement must exceed the suction pressure of the compressor. The relationship between compressor suction pressure, operating gas lift pressure and the injection gas requirement are beyond the scope of this article. However, the effect of injection gas pressure and suction pressure on injection gas requirements and compressor costs are illustrated in Table 10, page 80 of **The Power of Gas** by C. V. Kirkpatrick.

Operators report an unaccountable gas loss in most closed rotative systems. The bulk of these losses are believed due to error in gas measurement; however, it is advisable to include in the gas requirement for selecting a compressor deliverability this unaccountable loss. An unaccountable loss of approximately four per cent of the deliverability of the compressor is recommended for the design of most systems.

An estimation of the daily injection gas requirement for sizing the compressor station can be calculated as follows.

1. Tabulate the producing data (present and abandonment) for all wells to be included in the closed rotative system. This data should include total producing rate, gas-oil ratio, water cut, depth of producing zone, static bottom hole pressure, productivity index, wellhead tubing pressure, oil gravity, water gravity, tubing size, casing size, etc.
2. Group wells into as few representative wells as possible. The wells should be divided into categories based on types of gas lift installation, depth of operating valve, producing rate, etc. This reduces the number of required calculations.
3. Calculate the gas requirement for each representative well for present and final producing rates. The gas requirement for an intermittent installation should be calculated based on the injection gas required to fill the tubing under the slug.[1] Flowing gradient curves or volumetric balance calculations should be used to determine the gas requirement for a continuous flow installation.[2,3]
4. Multiply the gas requirement for each representative well by the number of wells in each category to obtain the total gas requirement per category. Then gas requirements for all categories are totaled and the unaccountable gas loss for the system is added to obtain the total daily gas requirement needed for compressor calculations.

Calculation of approximate compressor brake horsepower

1. Select a suction and discharge pressure for the compressor. Compressor discharge pressure should be 100-200 psi higher than the operating injection pressure required to lift the intermittent wells. A line pressure higher than operating pressure assures gas storage in the high pressure system, due to a pressure difference, and permits use of higher opening pressure gas lift valves for unloading the well. Suction pressure must be less than the wellhead tubing pressure assumed for calculating injection gas requirements.
2. Calculate the approximate compressor brake horsepower for present and maximum injection gas requirements using curves supplied by a compressor manufacturer, or the compressor brake horsepower calculation curves in the *Natural Gasoline Supply Men's Association Engineering Data Handbook*. The total daily injection gas volume must be corrected to a pressure base of 14.4 psia and intake temperature before the brake horsepower can be calculated from most compressor design curves.
3. Select a nominal brake horsepower rated compressor which exceeds the brake horsepower requirement calculated above. Many times the compressor installation is designed initially for the present gas requirement and compressors added as needed. The brake horsepower rating of the initial compressor should be based on the brake horsepower of the final compressor station in order that the compressor station required to deplete the wells will not consist of an excessive number of small brake horsepower compressors.
4. Contact the manufacturer for specific sizing of the compressor. Prior to contacting this representative,

tabulate the data needed to accurately size a compressor. This data should include: ratio of specific heat ("N" value) of the gas, suction pressure, discharge pressure, intake gas temperature, volume of gas at given pressure and temperature base, atmospheric pressure, ambient air temperature, etc.

Two-stage horizontal type belt-driven compressor units are available in nominal ratings of approximately 70, 120, 200 and 310 bhp. Horizontal balanced opposed direct drive units are offered in 100 to 450 bhp ratings. Integral skid-mounted compressor units rated at 175 to over 1,000 bhp are available, with the 440 to 660 bhp units being the most popular sizes of integral compressor units used for gas lift service.

The bhp rating will vary slightly between manufacturers; but generally, compressor units offered by various manufacturers are competitive in size and price for each type.

An excessive number of small brake horsepower compressors increases detailed attention and maintenance and will increase the final cost of a compressor station. The difference in cost between very small compressors based on dollars per bhp can be significant and can be illustrated by a recent quotation for two skid-mounted two-stage horizontal type belt-driven compressor units complete with prime mover, scrubbers, coolers, safety switches, etc.

A two-stage, 80 bhp, 8 inch x 4 inch x 9 inch compressor capable of delivering 425,000 cubic feet per day at 14.4 psia and inlet temperature with a suction pressure of 20 psig and a discharge pressure of 600 psig costs approximately $20,250 f.o.b. Houston, Texas. A two-stage, 5½ inch x 4 inch x 9 inch compressor, capable of delivering only 185,000 cubic feet per day with same suction and discharge pressures, costs approximately $19,000 f.o.b. Houston, Texas.

Design of high-pressure injection gas system. If injection gas enters the casing of all wells at a constant rate through a small restriction in the injection gas line, high pressure system design is of no concern. When surface controllers with a time cycle pilot are used, the injection gas requirement is high during the time that the controller is open, and no injection gas is needed for the long periods of time that the controller is closed.

The high pressure system should be designed to supply the difference between the deliverability of the compressor station and the injection gas requirement to lift the wells during the time that the surface controllers are open. Abandoned wells can be used for increasing the capacity of the high pressure system.

One of the most important concepts in design of both the high and low pressure systems is that there is no gas volume stored in a conduit above a given pressure unless there is both capacity and pressure difference (pressure of gas must be higher than given pressure). Capacity is a fixed value based on the physical size of the conduit. Gas volume varies with the capacity of the conduit and the pressure and temperature of the gas.

Higher pressure differentials and, consequently, greater gas volumes for the same capacity, are possible in the high pressure system than in the low pressure system. The following equation, which disregards gas deviation and temperature correction, can be used for approximate calculations of gas volume-in and capacities-of the high and low pressure systems:

$$\text{Approximate Gas Volume at Atmospheric Pressure} = \left[\frac{\text{Pressure Difference}}{\text{Atmospheric Pressure}}\right] \text{Capacity} \quad \ldots (1)$$

A standard pressure base may be substituted for the atmospheric pressure term if the volume of gas at a given pressure base is desired. Generally, the gas deviation tends to partially offset the temperature correction in calculations relating to the high-pressure system.

1. Calculate the deliverability of the compressor during the time that a surface controller is open.
2. Calculate the difference between the compressor deliverability and the injection gas requirement during the time that injection gas is entering the wells. This volume of injection gas must be stored in the high pressure system.
3. Calculate the approximate capacity of the high pressure system using Equation 1. This calculation is based on the minimum volume of gas calculated in Step 2 which must be stored in the high pressure system, the injection gas line pressure immediately before the surface controllers open and the maximum casing pressure build-up during the time that the surface controllers are open.
4. Calculate the pressure loss in the longest and/or smallest ID injection gas line in the system. The per-minute gas requirement must be converted to an hourly or daily basis to use most gas flow equations. An alignment chart for the solution of Weymouth's formula of gas flow in small high pressure lines can be used to find pressure loss with relation to daily gas volume and upstream pressure.[5] If pressure loss is excessive, larger lines should be used.

Calculation of excess or make-up gas volume. The excess or make-up gas volume should be based on the produced gas from the wells, fuel requirement of the compressor station, and any miscellaneous gas losses in the system. It is advisable to base these calculations on an unaccountable loss in the system of approximately 4 percent of the deliverability of the compressor station if no actual data on losses are available.

If the wells have a high gas-oil ratio and a high pressure gas sales line is nearby, the operator should consider sizing the compressor for the additional capacity required to deliver the excess gas into the high pressure sales line.

1. Calculate the total daily produced formation gas from the wells. Multiply the gas-oil ratio times the daily oil producing rate from each well and total these volumes of gas.
2. Calculate the daily fuel requirement for operating the compressor station. Fuel consumption of a gas engine prime mover for a compressor can be estimated by assuming a gas requirement of approximately 10 cu.ft./bhp-hour.
3. Compare the total daily produced formation gas with the summation of the daily fuel requirement for the compressor station and the unaccountable volume of gas loss in the system. If the produced gas exceeds the

fuel requirement and the estimated unaccountable loss for the system, no make-up gas should be required, provided the closed rotative system is properly designed and operated.

Design of low pressure gas gathering system. When injection gas plus formation gas is entering the low pressure system at a constant or near constant rate (as from a continuous flow gas lift well), capacity of the low pressure system is of no importance. Although an intermittent gas lift installation may be designed for controlling the high pressure injection gas into the casing with a choke (continuous injection with no high rates for short periods of time), the total volume of gas-out returns to the system at a relatively high rate immediately after the slug surfaces. If the produced gas (injection and formation) cannot be stored within the low pressure gathering system, the gas will be vented or enter a sales line.

High gas-oil ratio wells which produce gas between injection gas cycles minimize the problems associated with the gas gathering system. Generally, the difference between compressor suction and maximum separator pressure is much less than the difference between casing pressure and injection gas line pressure. Consequently, an adequately sized low pressure system is important for small closed rotative systems with intermittent wells, if no central timer is used to operate the surface controllers. The gas gathering system for a closed rotative gas lift installation should include as many wells as possible, regardless of whether these wells are on gas lift.

In the following procedure, the gas gathering system is designed to retain the produced formation gas necessary to supply the fuel requirement for the prime mover of the compressor and the make-up gas volume based on an assumed percent unaccountable loss in the system.

1. Estimate the maximum volume of gas which will enter the low pressure gas gathering system during any given period of time that the deliverability and fuel requirement of the compressor station are exceeded. This calculation should be based on the maximum number of intermittent wells which could have a liquid slug entering the surface facilities simultaneously. An actual total gas-out chart from an intermittent well (Figure 2) will be used to illustrate these calculations.

   This estimation is the most difficult one to make in the design of a closed rotative system. An assumption which may be helpful is that approximately one-half of the total gas volume produced per cycle, which includes injection and formation gas, enters the gas gathering system in a five-minute interval, provided the well is not choked and the flow line is not extremely long or smaller than the tubing.

2. Calculate the gas volume required to supply the deliverability and the fuel requirement of the compressor station during the time that compressor capacity is exceeded.

   One method for calculating this total gas volume is to multiply the summation of these daily gas volumes by the number of minutes that the capacity of the compressor is exceeded and divide the result by 1,440. The daily fuel requirement was computed in the previous calculations for determining the excess or make-up gas volume.

3. Calculate the volume of excess gas which can be sold or vented per cycle from the low pressure system if the produced gas from the wells exceeds the summation of the fuel requirement and deliverability of the compressor station. This gas volume is obtained by dividing the estimated excess daily gas volume which can be sold or vented by the number of injection gas cycles per day. For the design of the low pressure system, all gas is assumed to be vented or sold from the system during the time that the capacity and fuel requirement of the compressor are exceeded.

4. Calculate the volume of gas which should remain in the low pressure system during the period of high rate of gas entry into the system. For the period of time that the compressor capacity and fuel requirement are exceeded, subtract the volume of gas required for deliverability and fuel requirement calculated in step 2 and the volume of excess gas which can be sold or vented calculated in step 3 from the maximum volume of gas entering the low pressure system during the same period calculated in step 1.

5. Calculate the approximate capacity of the low pressure system using Equation 1. These calculations are based on the volume of gas calculated in step 4, maximum separator pressure (due to sales line or vent line regulator opening pressure) and suction pressure of the compressor. In other words, the pressure of the gas gathering system is assumed to increase to the sales line or vent line regulator opening pressure during the time that the capacity of the compressor station is exceeded.

   When the rate of gas produced from the well is less than the deliverability and fuel requirement of the compressor station, the pressure of the gas gathering system begins to decrease. When compressor suction pressure is reached, gas from the wells enters the gathering system at a rate which exceeds the capacity and fuel requirement of the compressor station and the cycle repeats.

6. Select adequately sized flow lines and eliminate as many restrictions, bends, fittings, etc., as possible between the wellhead and separator. The flow line should never be smaller than the tubing in the well, and preferably larger. If the well will eventually have a high water cut and must be produced at a high rate, flow lines should be sized initially for maximum fluid production at depletion.

If it is difficult to retain gas in the low pressure gathering system, choking the intermittent wells at the battery may solve the problem. An intermittent gas lift well should not be choked at the wellhead. An inexpensive source of additional low pressure capacity can be obtained by using large obsolete separators with all internal parts removed.

This article is a revised version of a paper presented to The West Texas Oil Lifting Short Course at Texas Technological College, Lubbock, April 1960.

Part 2 of this article which will appear next month, will contain an actual sample calculation for each of the previously described procedures.

TO BE CONTINUED

How to get top performance from your V-belt drives

For maximum efficiency, V-belts must be matched, properly installed, inspected at regular intervals and adequately stored when they are not in use

By A. E. Poehlmann, Executive Engineer
The Gates Rubber Company, Denver

MULTIPLE V-BELT DRIVE are widely accepted as a satisfactory method of mechanical power transmission because they:

- Handle large fluctuations in load
- Are exceptionally resilient
- Require less tension than flat belts
- Operate at lower bearing loads
- Are just as efficient on short center distances as on long ones
- Need a minimum amount of maintenance.

SELECT ONLY MATCHED SETS OF V-BELTS

Matched sets from one manufacture should be used. If different makes of belts are used, it is likely their pitch lines (see Figure 1) will differ. Mismatched belts tend to travel at different speeds and work against other belts in the drive. Too, tensile members in different manufacturers' belts are not made of the same material and growth characteristics eventually may cause belts to stretch unevenly, resulting in a set of mismatched belts.

How are matched sets obtained? Next to the label on every V-belt is a matching number, such as the numbers in Figure 2. These numbers are stamped on the belt at the factory. When selecting V-belts with outside circumferences of less than 100 inches, belts with the same matching number should be selected. For longer belts a spread of an additional consecutive matching number for each additional 100 inches of belt length can be used.

New and used belts should not be used as a set because the new belts are usually shorter and they have a tendency to ride higher in the grooves and carry more than their share of the load. However, old belts should be saved until a complete set can be adjusted to operate at approximately the same pitch line and tension.

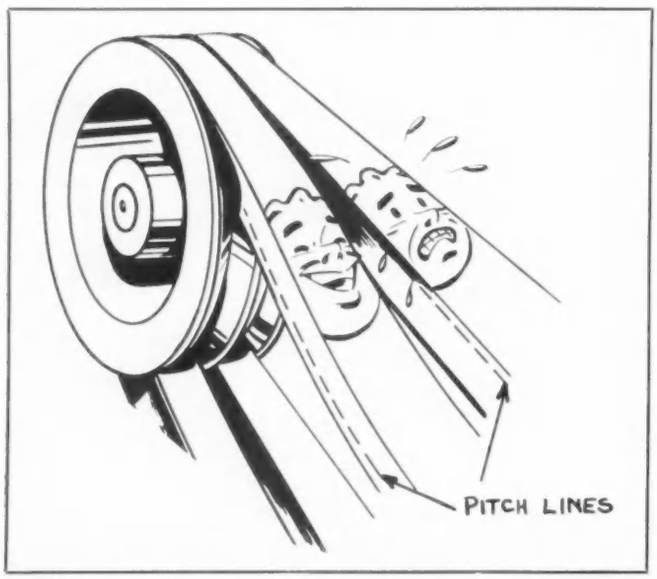

FIGURE 1—Pitch lines will vary with different manufacturers and will have a direct bearing on speed of travel.

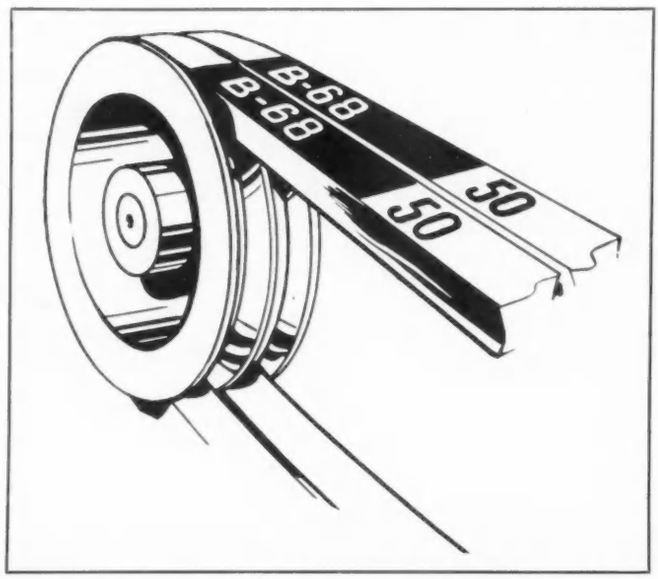

FIGURE 2—The V-Belt should be matched sets and can be checked from corresponding markings on the belt.

INSTALLATION OF V-BELTS IS IMPORTANT

The most important element of any V-belt drive is the installation. A properly installed drive is easy to keep in top running condition. By observing the following procedures, a trouble-free drive can be assured:

- Clean oil and grease from sheaves grooves. A clean surface gives the belts a chance to secure the greatest wedging effect.

  Remove nicks and burrs from grooves. This prevents belt damage and premature failure.

  Replace sheaves with badly worn grooves. Excessive groove wear causes V-belts to ride lower and bottom on the shoulders worn in the groove. This cuts down gripping power. It may even cause slippage and shorten belt life.

  Replace damage bushings or bent shafts. These may cause a sheave to wobble or run eccentric, which in turn, causes the belts to whip, weaken tensile members, and shorten belt life.

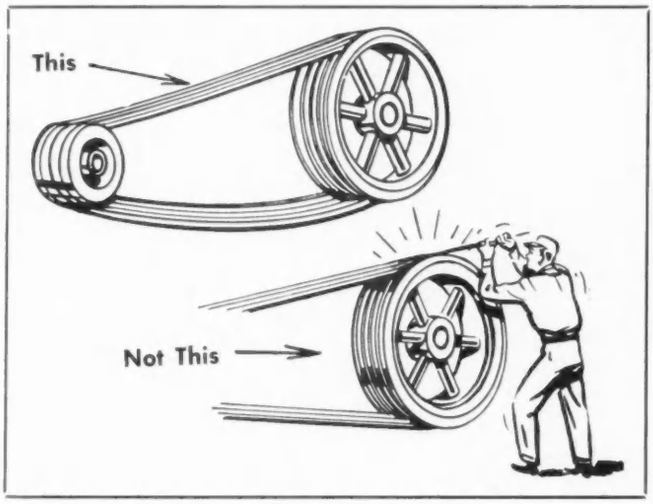

FIGURE 3

- Slack off the drive and apply the belts without prying extreme force (see Figure 3). Forcing a belt over the edge of the sheave may break its tensile cords and destroy its usefulness. Also, a weakened belt is more likely to turn over in a groove.

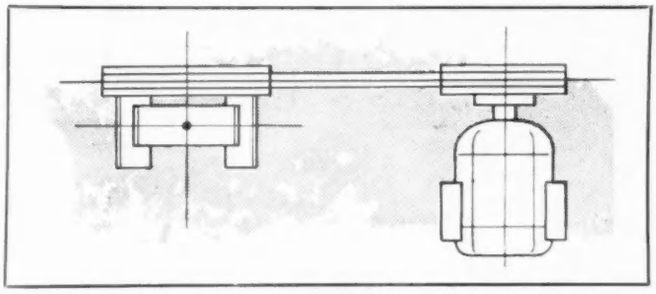

FIGURE 4

- Place shafts exactly parallel as shown in Figure 4. When shafts are not parallel, V-belts are under uneven tension from one side of the drive to the other.

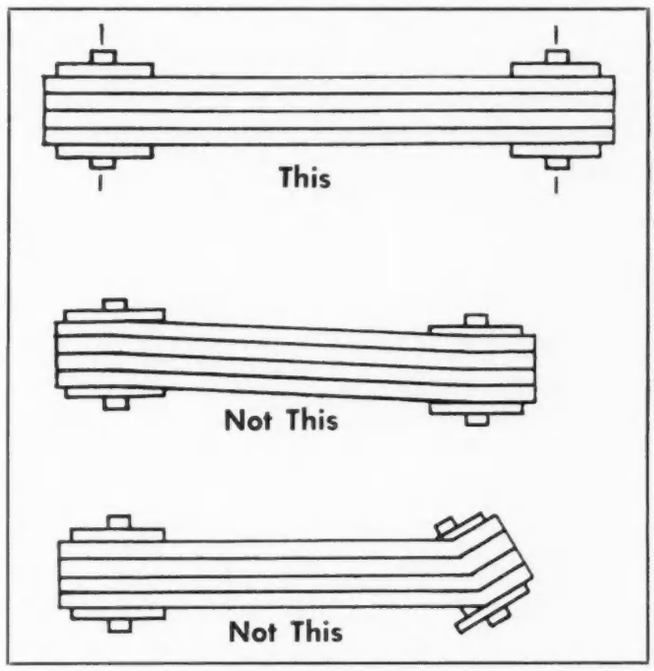

FIGURE 5

Align the sheaves so that belts enter and leave the grooves in a straight line, and without rubbing against the edges of the grooves (see Figure 5). Belts last longer when these alignments are made.

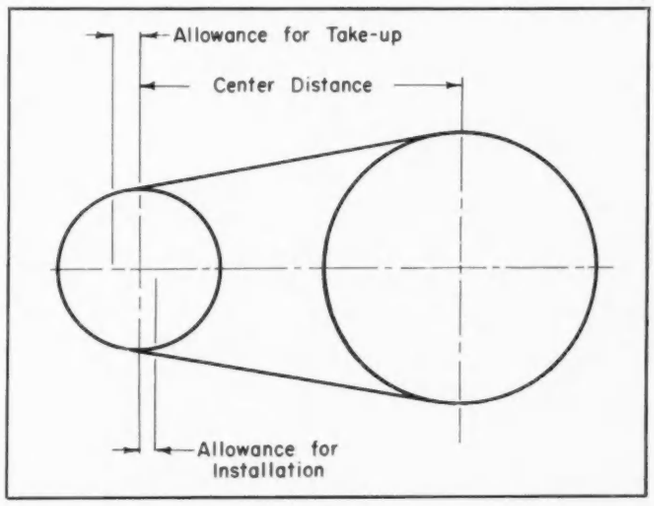

FIGURE 6

- Sufficient provisions should be made for installation and take-up (see Figure 6). This is necessary to take care of stretch and wear, to get maximum life from V-belts. The recommended adjustment for this take-up is 3 percent of belt length.
- With the belts in place and sheaves properly aligned, adjust the take-up until the belts are fairly snug in the grooves. Then tighten down the motor and start it to see if the belts have the necessary "bow" on the slack side.

  If the belts screech when starting up or on overload, tension is not sufficient. The drive should be tightened even more.

  After a few hours load, check belts again and re-

adjust tension till there is again just a slight "bow" on the slack side.

HOW TO MAINTAIN V-BELTS

V-belt drives give the best service when they are properly installed and regularly inspected and maintained. With an organized, regular inspection, items needing attention are detected before belt failure. Maintenance may be handled during regular downtime rather than as an emergency.

When visually inspecting a V-belt drive, see that the belts are uniformly tensioned on the tight side. Belts should not be sagging and should be riding at the same depth in the groove. Periodic adjustment of the take-up maintains proper tension and allows for the stretch and wear. Check also to see that the belts are not striking a guard or any other obstruction. The sheaves may not have been replaced in their original position or possibly the guard may have been deformed.

Occasionally inspections may show that a problem exists whereby the sheave grooves may be all right, the drive may be properly aligned, but still the belts are receiving a short service life. In this case, check the stock records. Find out how often the belts were replaced on the specific machine and on similar drives. Also, possibly the load may have increased since the drive was designed and the drive has not been redesigned to compensate for this condition.

On other occasions, the belts may have stretched beyond their take-up allowance. Again, check the stock records, and perhaps a change in load or an underdesigned drive may exist. The drive also should be checked for excessive tension whereby this condition could cause V-belts to grow or stretch abnormally. The belts may also be the wrong sizes and may not fit the sheaves properly. This situation may be alleviated by installing a matched set of the correct size.

A squealing drive usually is a result of belt slippage due to insufficient tension or too heavy a load on the drive. Never try to correct a slippage problem by applying dressing to V-belts.

Belt dressings are intended for flat belts. Most dressings contain chemicals that act as a solvent and soften the rubber in V-belts. When this happens, V-belts become tacky and often stick in the grooves resulting in a tearing condition of the hide. This tacky situation also causes belts to pick up dirt and sand which promotes abrasive wear on both belts and grooves.

In addition, This build-up of dirt and grit in the grooves reaches a point where the belts ride on dirt and cease to grip the sheave walls and the advantage of V-belts in sheave grooves then is lost.

The problem of belt slippage may be solved by cleaning the drive and applying the proper tension. If this doesn't help, the drive is probably overloaded and needs to be redesigned.

PROPER STORAGE MEANS LONGER LIFE

V-belts should be stored in a cool, dark place away from radiators and out of direct sunlight. During storage, heat dries the oil out of V-belts and causes them to become hard and brittle.

If space permits, belts should be uncoiled and hung over pegs in a rack or on a wall (see Figure 7). Stored in this way, V-belts will keep for years.

Sheaves usually are made out of cast iron or steel and covered with a protective coat of paint. Nevertheless, sheaves should be stored indoors to prevent rust.

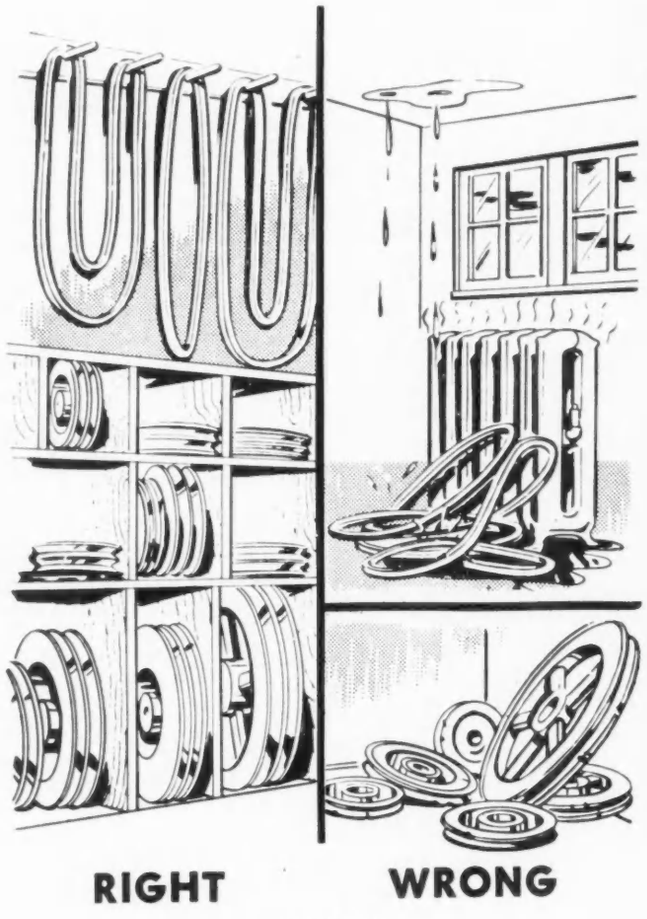

FIGURE 7

Sheave grooves are of considerable importance in the life of a V-belt drive. Mishandling and improper storage of sheaves is many times the cause of premature wear on V-belts. Sheaves should be protected at all times to prevent contact with other sheaves or hard surfaces.

Never roll a sheave along hard floors. This can result in burrs on top of the grooves which will abrade the belt and shorten its life. —**The End**

About the Author

Alfred E. Poehlmann is the Gates Rubber Company executive engineer and specialist in V-belt application and maintenance. He joined Gates in 1947 and now shares responsibility for the development of the V-belt OEM market. Poehlmann has lectured extensively to European, Canadian and American agricultural and automotive equipment engineers on the theory and application of V-belt engineering, drive design and power transmission. After graduating from the University of Wisconsin in 1933, Poehlmann joined the John Deere Tractor Company as an experimental engineer. He is a member of the SAE and ASAE.

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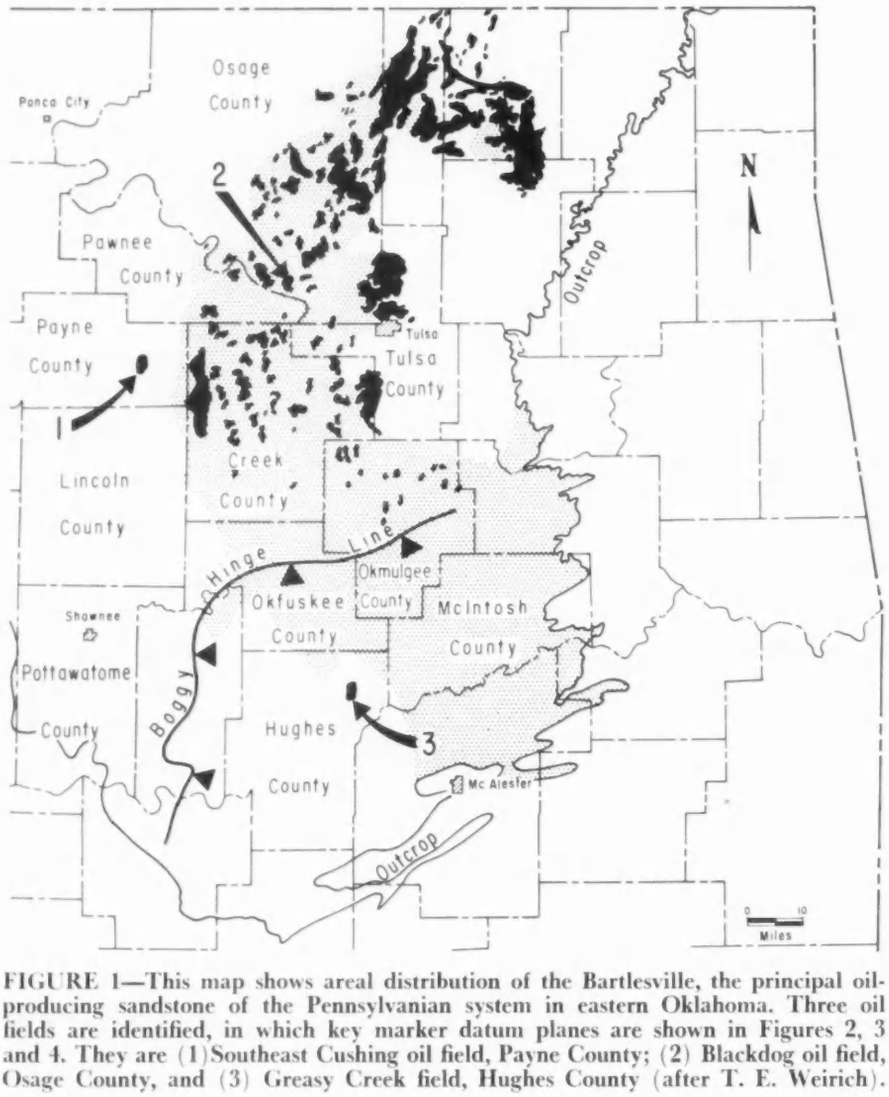

FIGURE 1—This map shows areal distribution of the Bartlesville, the principal oil-producing sandstone of the Pennsylvanian system in eastern Oklahoma. Three oil fields are identified, in which key marker datum planes are shown in Figures 2, 3 and 4. They are (1) Southeast Cushing oil field, Payne County; (2) Blackdog oil field, Osage County, and (3) Greasy Creek field, Hughes County (after T. E. Weirich).

How to choose eastern Oklahoma datum planes

Rapid lower Pennsylvanian facies changes in McAlester Basin make marker choices crucial

By Joseph A. Kornfeld, President
Kornfeld International, Tulsa

SELECTION OF KEY MARKER reference datum planes in the lower Pennsylvanian system of eastern Oklahoma presents difficulties owing to rapid stratigraphic changes. Since so much production is controlled by stratigraphic traps in this region, correct selection of datum planes is essential to effective mapping and to successful exploration based on subsurface geology and geophysics.

Regional continuity. The principal requirement in selection is the regional continuity of the key marker bed over a wide geographic area. For example, Oswego limestone is recognizable throughout the northern mid-continent region as one of the most persistent and regular key marker datum planes in the lower Pennsylvanian system. This limestone lies above most of the principal oil-producing fields in eastern Oklahoma. Mapping on the *base* of the Oswego is preferable to the top due to shoaling lithology of its surface.

Geological reliability. The next most important factor in selection is that the key marker should neither conclude a major cycle of sedimentation nor represent a major erosional surface or unconformity.

The base of a widespread massive carbonate series, i.e., the base of the Kansas City limestone series of the central Kansas uplift may make a good marker; or the base of a regionally persistent, diagnostic shale, i.e., the base of the Heebner shale; or the top of a persistent coal, or the base of a thin regional biostrome.

Ease of recognition. Provided that the prior two major factors are met, a key marker should be easily detected from electric or radioactivity well logs. Easy lithologic recognition from sample logs is also important.

Proximity to objectives. Another important factor is selection of a marker which lies at a relatively short interval above the top of the objective reservoir. In the case of a sequence from a massive sandstone through a shaly sandstone phase into a sandy shale, it is desirable to select the top of the most persistent limestone or coal occurring immediately above the objective horizon, provided there are no intervening unconformities. For example, in development of the Red Fork sandstone, the Pink limestone which lies at an interval of about 50 feet above the top of the sandstone in the Drumright field of Creek County, Oklahoma, satisfies not only the requirement of proximity to objective, but the other factors of regional con-

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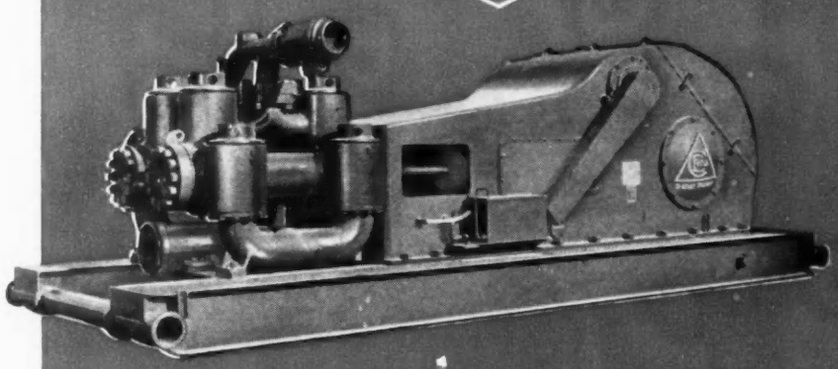

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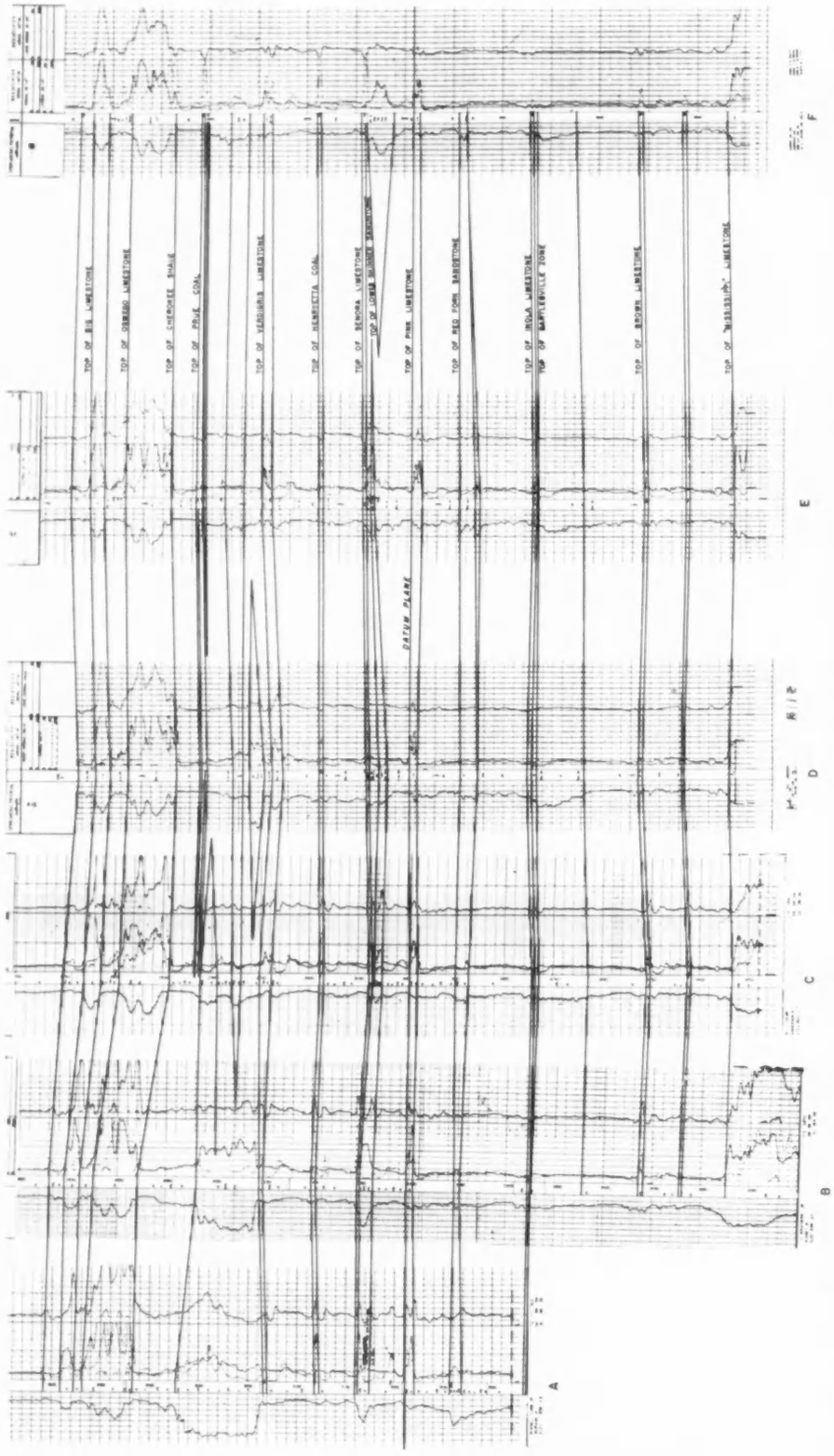

FIGURE 2—Stratigraphic cross-section across the Southeast Cushing oil field, Payne County, Oklahoma, from west (left) to east (right). Significant lithologic changes in the Red Fork sandstone account for oil production in Well A and salt water in the Red Fork in the other wells shown. The datum plane used is the top of the Pink limestone.

tinuity, geological reliability, and ease of recognition on well logs.

PRINCIPAL DATUM PLANES

Six key marker datum planes commonly employed in mapping eastern Oklahoma are discussed in this article.

Lenapah limestone. The Lenapah limestone finds some utility in subsurface structural mapping of the Wayside sandstone oil reservoirs in northeastern Oklahoma. Despite the difficulty of detecting the Lenapah limestone on electrical logs, this marker finds wide application throughout northern Osage County. It grades into the underlying Wayside sandstone series.

Oswego limestone. The Oswego limestone is considered a major reference datum plane in northeastern Oklahoma. The formation can be traced with reliability throughout most of the principal lower Pennsylvanian oil producing areas of eastern, central and western Oklahoma. As stated previously, the base of this carbonate series is more desirable than the top due to the occurrence of limestone stringers at the top of the Oswego limestone sequence in certain areas of eastern Oklahoma. These stringers confuse proper detection of the surface from electric or radioactivity logs.

Verdigris limestone. The top of the Verdigris limestone series is one of the closing carbonate sequence of the Cherokee shale series of the lower Pennsylvanian system. It finds application in reservoir studies of the overlying Prue sandstone and the underlying Skinner sandstone series.

"Pink" limestone. The need for a reliable datum plane between the base of the Oswego limestone series and the base of the Pennsylvanian in eastern Oklahoma is met by the selection of the "Pink lime." It is regionally persistent, geologically reliable, and is easily identifiable from samples, electrical and radioactivity well logs.

Inola limestone. The Inola limestone is the most reliable key marker reference datum plane employed for study of the underlying Bartlesville sandstone series. It is easily recognizable from contact electrical logs, and

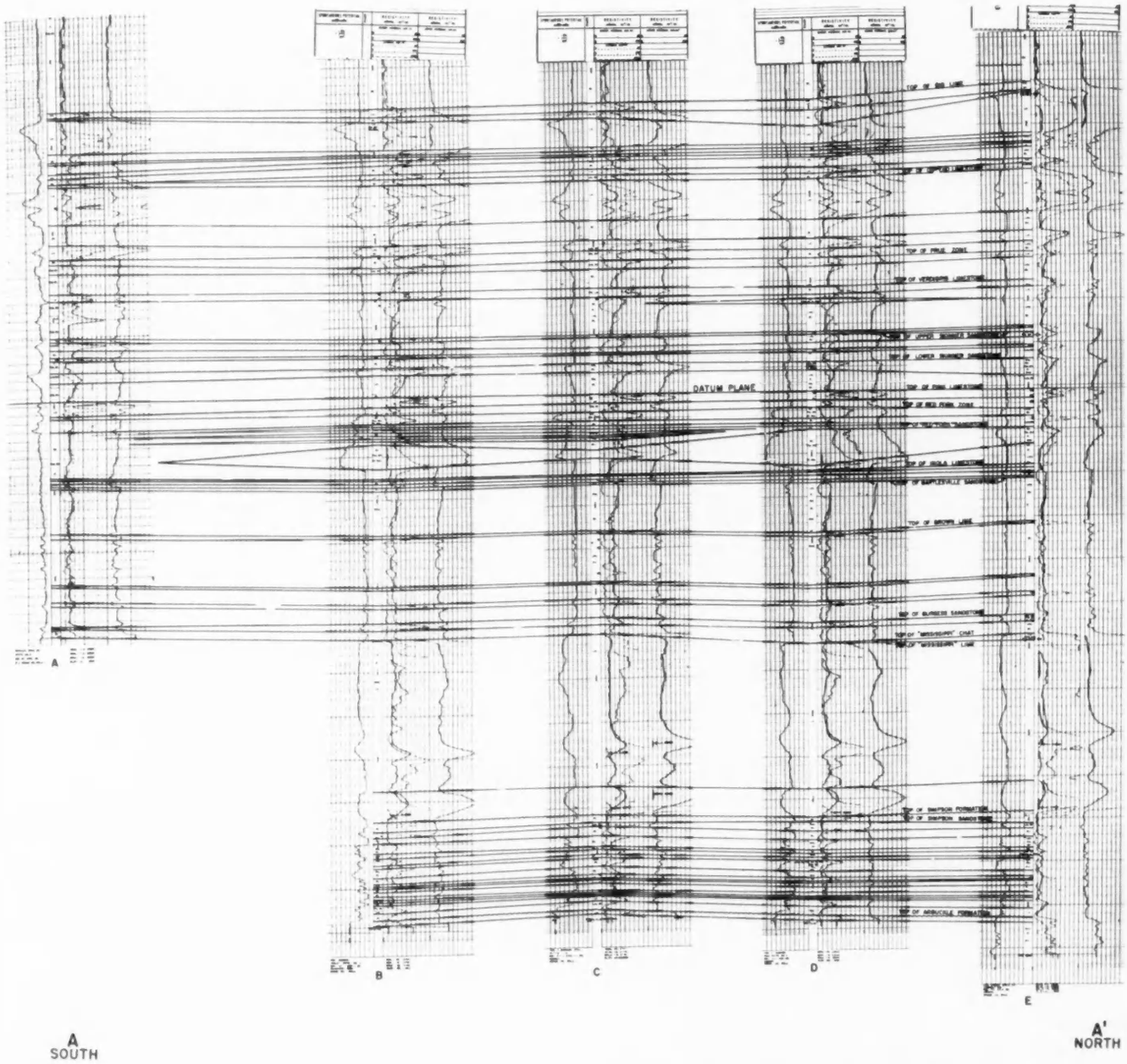

FIGURE 3—This is a stratigraphic cross-section running through the Blackdog oil field, Osage County, Oklahoma, from south (left) to north (right). Principal oil-productive zones are the Simpson and Arbuckle. Primary datum plane is the top of the Pink limestone. Regularity of the interval between tops of the Pink and Inola limestones is striking, despite lenticularity of the Red Fork sandstone between.

to a lesser extent from conventional electric logs or from well samples.

Brown limestone. Below the Bartlesville sandstone, the Brown limestone is a persistent, reliable and valid key marker reference for mapping the Booch, Hartshorne and Gilcrease sandstone series throughout Hughes, McIntosh, Okmulgee and other countries in the McAlester Basin.

Cross-section. Three geological cross-sections have been selected from various parts of the lower Pennsylvanian system of eastern Oklahoma to illustrate this article.

Top of pink limestone. The utility of the top of the Pink limestone is illustrated by the choice of two geologic cross-sections constructed to this datum plane. A good illustration of the application of the Pink limestone is shown in Figure 2, Southeast Cushing oil field, Payne County, Oklahoma. This figure shows changes in the Red Fork sandstone which account for oil production in Well A and salt water from the same formation in all other wells shown. This same information would be contained in a structural datum plane cross-

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* If you count the pictures, you come to number 9. But that's certainly not the total of packers made by Baker. For instance, Models "J" & "K" Snap-Set Packers are also made in double-grip versions. Model "E" is also offered with integral one-shot unloader, or with unloader and hold-down. Moreover, thanks to Baker's continuing program of packer research and development, new packers that will supplement the packers pictured above are coming.

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(left)
Model "J" Single-Grip Snap-Set Dual Packer
Product No. 756-J

(right)
Model "K" Single-Grip Snap-Set Dual Packer
Product No. 756-K

BAKER MODEL "M" SNAP-SET PACKERS

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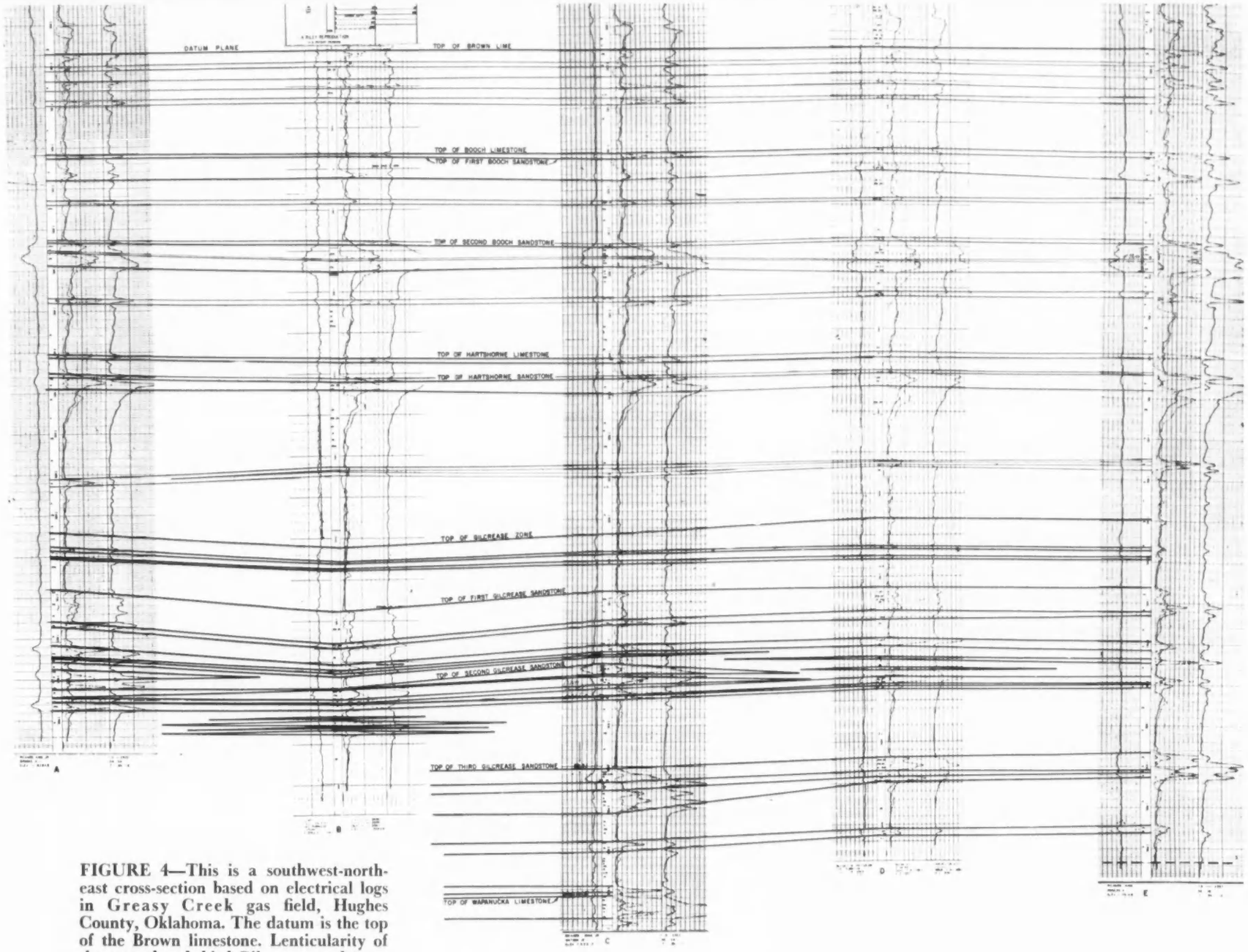


FIGURE 4—This is a southwest-northeast cross-section based on electrical logs in Greasy Creek gas field, Hughes County, Oklahoma. The datum is the top of the Brown limestone. Lenticularity of the second and third Gilcrease sandstones is emphasized by this mode of presentation.

A

About the Author

Joseph A. Kornfeld is president of Kornfeld International, consulting petroleum technologists, Tulsa. He has widespread international experience in geological and engineering studies of exploration and production operations. Kornfeld is a faculty member of the School of Gas Technology sponsored by the Petroleum Extension Service of The University of Texas. He has lectured at the Algiers and Mexico City sessions of the International Geological Congress during 1952 and 1956, and at the Paris and Munich conferences of the International Convention on Pure and Applied Chemistry during 1957 and 1959.

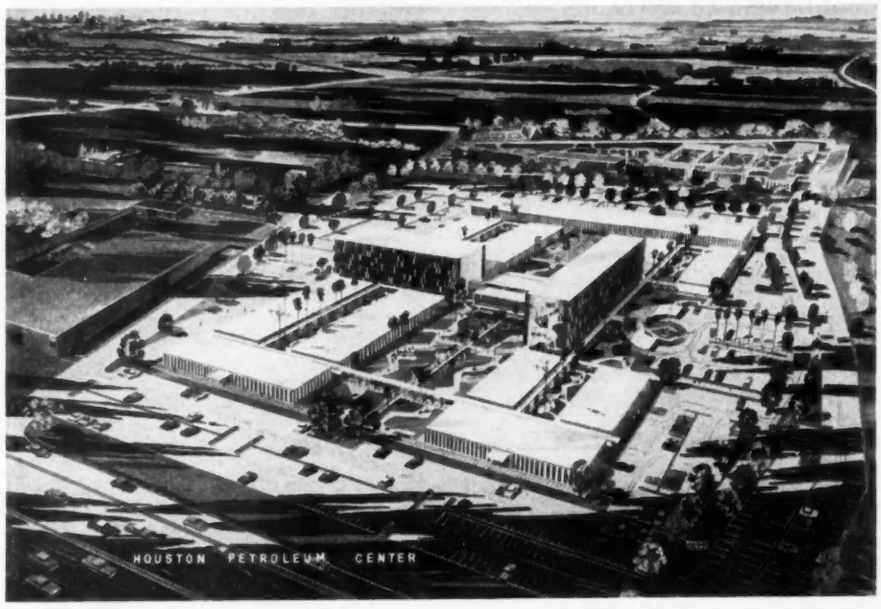
section but the emphasis would not be obvious.

Another example of the utility of the Pink limestone in geologic correlation is shown in Figure 3, Blackdog Dome oil field, Osage County, Oklahoma. Note the regularity of the interval between the tops of the Pink and Inola limestones, particularly when compared with the irregular sedimentation of the intervening Red Fork sandstone which produces oil west of this area. The principal oil producing formations at Blackdog are the Simpson sandstone series and the Arbuckle dolomite.

Note the reliability of the base of the Oswego limestone in this area and the lack of reliability of the top of the Big limestone.

Top of Brown limestone. Use of the top of the Brown limestone as a key marker datum for the lower Pennsylvanian system of eastern Oklahoma is well illustrated in Figure 4, Greasy Creek oil field, Hughes County. Although the first and second Booch and Hartshorne sandstones reflect regularity in sedimentation, there are highly significant variations in the stratigraphy of the second and third Gilcrease sandstones which are emphasized by this type of datum plane cross-section. —**The End**

Your industry at work



This is an artist's conception of the proposed oil center planned by Houston Petroleum Center Inc.

$7 Million Oil Center Planned for Houston

A $7 million 14-building center for the oil industry will be constructed in Houston by Houston Petroleum Center Inc. Announcement of the project was made by William A. Smith, chairman of the board of the newly formed company.

To be the largest of its kind in the United States, the center will occupy 26½ acres on Houston's Gulf Freeway midway between downtown Houston and the International Airport. It will include an eight story building, a seven story building, two 2-story and 10 one story buildings. It will contain a total of 342,000 square feet of office space, a two-story exhibition hall and will provide parking facilities for 1,700 cars.

Complete services for companies in the petroleum and allied fields will be provided by the center. They include microfilming, secretarial and answering services, messenger and intercom facilities.

Plans are to construct the center in phases with the first phase to begin late this summer, he said. This portion of the project is expected to be completed and ready for occupancy by early 1961.

Serving on the board of directors for Houston Petroleum Center Inc., in addition to Smith and West are: J. F. Eubank, vice president; F. W. Eubank, Tyson Smith, Joe E. Coleman, Joseph W. Moore, all of Houston, and W. D. Welder of Victoria.

Standard of Indiana Revamps Engineering Department

Standard Oil Company (Indiana) has put into effect its efforts of streamlining of the General Engineering Department for greater efficiency.

George M. Keranen, manager of the General Engineering Department, will now be assisted by four assistant managers instead of two in the alignment. Reporting to Keranen will be C. E. Evans, planning and operation; W. G. Guild, design; W. K. Brown, projects, and Ben Franklin, contracts, construction and estimating. Brown and Franklin are named to newly created positions.

Stanton Oil Company, Ltd. Purchases Interests in Texas

Stanton Oil Company, Ltd., of San Antonio, Texas, has purchased from Sapphire American Petroleums, Inc., all of its interests in West Texas. The deal involves 2,000 acres of proven leases in Cochran County, Texas. There are 11 producing wells on the properties at present, two gas wells and nine oil wells. Stanton plans to develop the remaining acreage.

Sapphire is a Canadian-based company, its parent company being Sapphire Petroleums, Inc., of Toronto, Ont.

Pan American's $36,000 Benefits Three Universities

Pan American Petroleum Corporation recently disclosed the donation of scientific equipment estimated to exceed $36,000 to three universities. Donations of the equipment were to the University of Kentucky, Rice University and the University of Tulsa. The equipment has been on loan to the three schools since September 1959, to aid in various research studies.

It includes a magnetic susceptibility balance and infrared analyzer, to the University of Kentucky; a Logan pump and pressure intensifier to Rice, and a thermoluminescence analyzer and 10 special file cabinets to the University of Tulsa.

Your industry at work

Sunray Mid-Continent Combines Two Divisions

Sunray Mid-Continent Oil Company recently consolidated its West Coast and Rocky Mountain Exploration and Production divisions into a new Western Division with headquarters in Denver.

John H. Douma, vice president and general manager of Sunray's West Coast Division, Los Angeles, will head the new division as vice president and manager. O. A. Graybeal, Sunray's West Coast Division production manager, has been named by Douma to fill the same position in the Western Division. T. A. Clote, Denver, Sunray's Rocky Mountain Division exploration manager, has been named as division exploration manager of the consolidated division.

Division personnel who are involved in the consolidation and who are presently located at the Los Angeles headquarters have been transferred to Denver. District production and exploration offices will be maintained in California at Newhall and Bakersfield. Other district offices in the new division are located at Salt Lake City, Utah; Casper, Wyo., and Denver.

Sunray's Western Division operations will be conducted in California, Oregon, Washington, Nevada, Utah, Idaho, Montana, North Dakota, South Dakota, Wyoming, Colorado, north and west Arizona, western Nebraska and the Four Corners area of New Mexico.

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Rainbo Service Co.....PL 6-2530
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Davis-Kemp Tool Co., Inc.....435
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Kline Wire Line Co.....OX 3-2731
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Hudson-Eads, Inc. 322-8584
WILLISTON, N. DAKOTA
C. A. White .....GR 3-6555

Men in the industry

Foreign Visitors Guests of Kerr-McGee

Recent guests of Kerr-McGee Oil Industries, Inc., in Oklahoma City were six Argentine congressional members and two representatives of the U.S. Department of State. In the rear are (left) Fernando Van Reigersberg and Jose A. Hervas, Department of State representatives. In the front are the Argentine congressional members: Francisco Jose Melani, Hector E. Figueros, Tomas Pedro Arana, Franklin Alberto Sanchez, Angel Oscar Prece and Jose I. Garcia Flores.

Robert R. Wallace has opened a petroleum consulting office in Dallas in the **North Ervay Building.** Wallace most recently was associated with Buffalo Petroleum Corporation in Fort Worth as assistant to the president. His background is in evaluation, reservoir engineering including pressure maintenance and waterflood projects, unitization and production engineering.

R. R. Wallace

J. H. Rankin continues as department head of the Production Department of **Sinclair Oil & Gas Company** which recently was changed to a full departmental status.

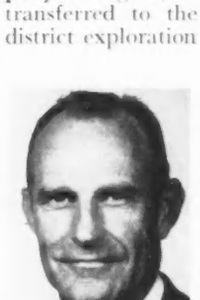
Dr. Parke A. Dickey has rejoined **Jersey Production Research Company** after a 20-months special assignment in Venezuela with **Creole Petroleum Corporation.** Dickey succeeded **Dr. R. W. Landes** as manager of the Geological Division at the research center.

Leslie M. Sellers, assistant district production superintendent for **Sinclair Oil & Gas Company** at Monahans, Texas, has been promoted to district superintendent and transferred to Silsbee, Texas. He succeeds **H. H. Morgan** who retired. **C. G. Confer,** assistant district superintendent at Hobbs, N.M., has been named to succeed Sellers at Monahans.

G. W. McMillan, formerly geologist in **Tennessee Gas and Oil Company's** Exploration Department, at Calgary, Alta., has been promoted to district geologist at Calgary. **R. I. Standen** has been named district landman in the Calgary office. He was formerly landman there. **Ray Blakely,** former geologist in Denver, has been promoted to district geologist there. He succeeds **C. S. Algire,** who transferred to Casper, Wyo., as district geologist.

Dr. J. R. Thomas has been appointed research scientist at the Richmond Laboratory of **California Research Corporation.**

George H. Davis, formerly district geologist for the **Colombian Sun Oil Company** in Bogota, Colombia, S.A., has been transferred to the Sun Oil Company's district exploration office in Pittsburgh.



W. S. Frisbie

W. S. Frisbie has transferred from the general offices of **Falcon Seaboard Drilling Company** in Tulsa, to a newly opened regional office in the Gulf States Building in Dallas. Frisbie will continue to serve as a special representative for the company, the same position he held in Tulsa.

Carl E. Totten has been named public relations manager for **Shell Oil Company** in Los Angeles. Totten replaces **J. H. Sembower** who resigned. For the past five years Totten has served as manager of News and Information in Shell's head office Public Relations Department in New York. Earlier he headed the Department's Special Projects Division.

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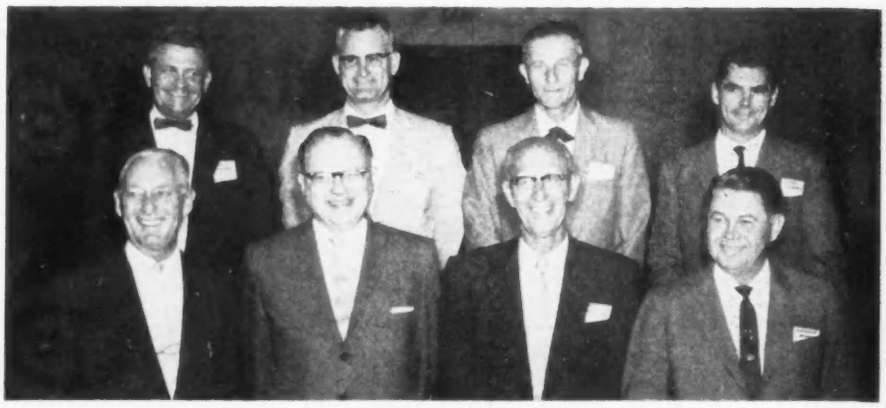
Men in the industry

J. H. Sneed is the resident manager of newly established office in Tripoli, Libya, by **Phillips Petroleum Company, Libya,** a wholly owned subsidiary of **Phillips Petroleum Company.** Also, **J. W. Bruynzeel, Jr.,** is the resident geologist in Libya. Other foreign offices opened and the operating personnel include: **S. K. Childers,** promoted from special representative, International Department, to manager of the new Madrid, Spain, office. He will direct all Spain-Spanish Sahara operations for the company. Also in Madrid, **R. E. Beck,** formerly chief geologist, Venezuela operations, promoted to exploration director for Spain and the Spanish Sahara, and **D. A. Butler,** who was advanced from geological engineer, International Department, to division geologist for Spain. **R. H. Ornelas,** formerly a senior field exploration geologist, Land and Geological Department, was transferred to the International Department and promoted to division geologist for Spanish Sahara operations with headquarters in Las Palmas, Canary Islands.

Marlin E. Sandlin, formerly vice president and general counsel of **Great Northern Oil Company,** has been elected chairman of the board of directors. Sandlin replaces **J. R. Parten,** also of Houston, who has retired.

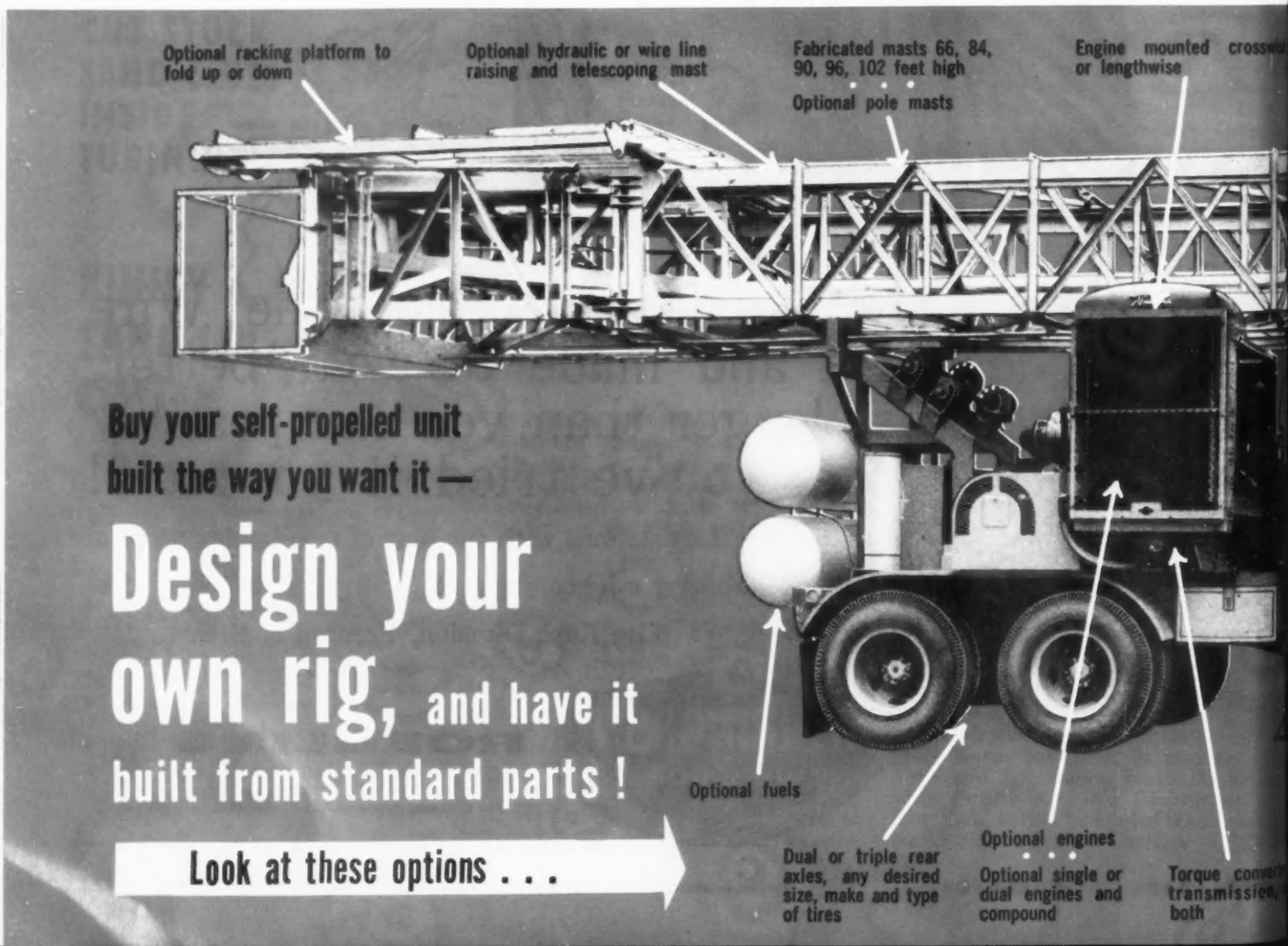


Guests and Speaker at Los Angeles NOMADS Meeting

International guests and speaker of the evening who attended a recent Los Angeles NOMADS meeting are left to right (front row): J. R. Tomlinson from Mexico; N. E. Shafer, speaker; Tommy Thompson of Brantly Drilling Co. from Brazil; George Murray of Petrobras from Brazil. Other guests were (back row); Fred Large of International Industrial Services, going to Libya; Fred Peveto of International Industrial Services, Inc., from Libya; Paul A. David of Petrobras from Brazil, and H. J. Clarke of British Petroleum from Das Island.

Roy F. Bennett has resigned from Sohio Petroleum Company as chief geophysicist and has opened his consulting office in Oklahoma City. Bennett is a past president of the Society of Exploration Geophysicists.

Paul D. Balbin has been named vice president of **Chaco Petroleum, S.A.,** a subsidiary of **Tennessee Overseas Company,** a division of **Tennessee Gas Transmission Company.** Also, **Luis G. Morales** has been named vice president of **Tennessee Argentina, S.A.**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Fabricated masts 66, 84, 90, 96, 102 feet high
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Torque converter transmission, both

Men in the industry

Carroll C. Cook has been named project manager in **Delhi-Taylor Oil Corporation's** Special Project and Planning Department. Cook formerly was assistant to Senior Vice President **Fred P. Sewell.**

H. Walton Musick has been appointed assistant director of purchases of **Kerr-McGee Oil Industries, Inc.** He was manager of the company's Office Service Department.

Earl Hollandsworth has been honored by the **Roughnecks Club** by being named the "Chief Roughneck for 1960." Hollandsworth was awarded a plaque which signifies he has contributed greatly toward America's leadership in oil and gas; that he has rendered rough and rugged service in the field and has achieved a place of honor in the industry.

E. Hollandsworth

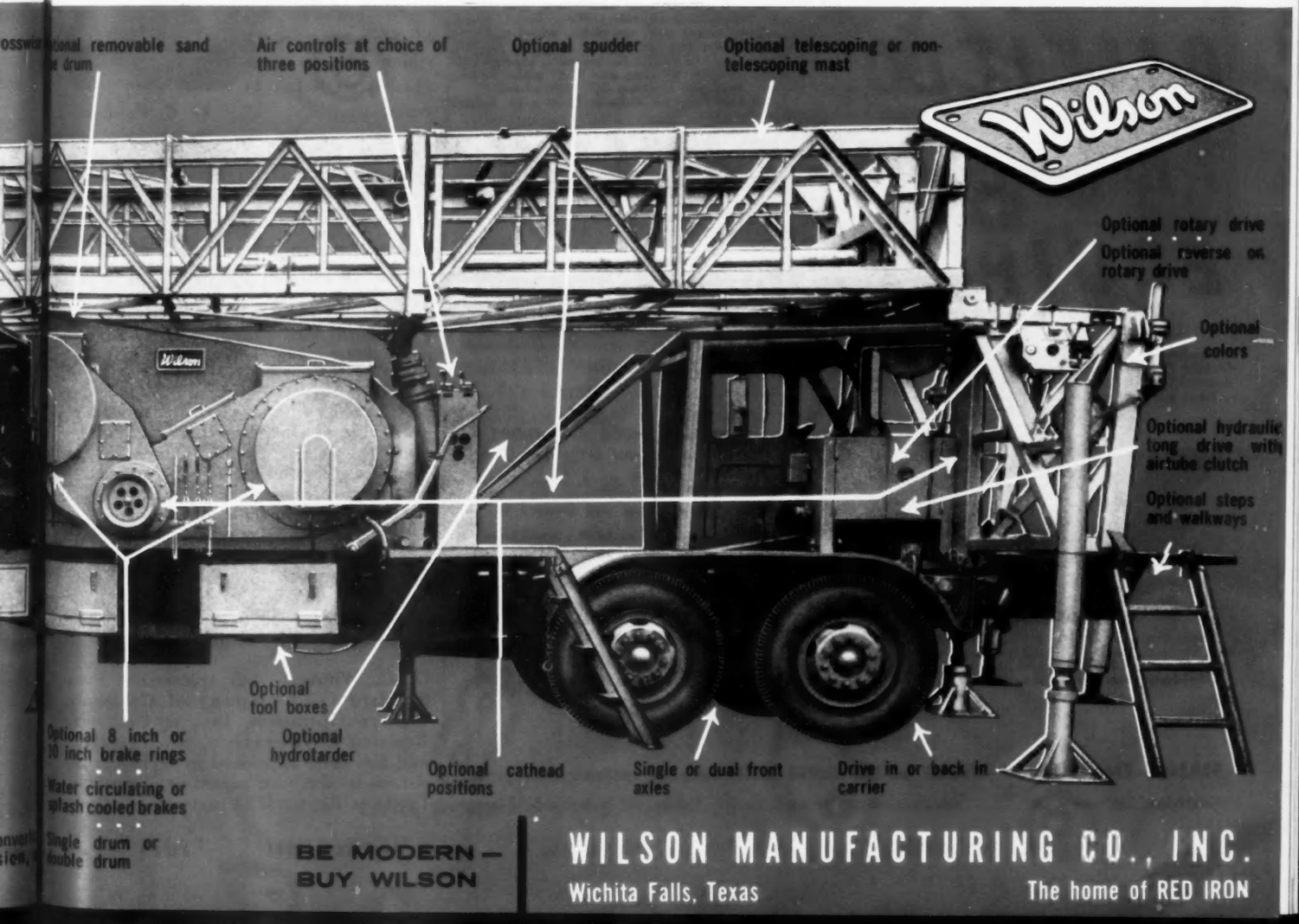
C. W. Smith has been appointed comptroller for **Mobil Oil Company's** Midland Exploration and Producing Division, replacing **R. C. Drummond** who was transferred to New York.

New York Members Honor Retiring NOMADS

The New York Chapter of NOMADS held a party recently honoring retired and soon to be retired industry friends of NOMADS. Those present for the party were (Seated left to right): J. Stanley, Esso (Libya); D. Moore, Esso (Libya); B. Finley, Standard-Vacuum Oil Co., (India); H. J. Clarke, British Petroleum, London, and G. Newson, Creole Petroleum Co., Venezuela. Standing were: J. F. McBride, Creole Petroleum Co., Venezuela; J. Gleason, California-Texas Oil Co., London; R. Norton, Kier & Crawder Arrow Drilling, and M. A. Reber.

C. K. Shepherd has been promoted to general manager of **Continental Oil Company's** Central Region with headquarters in Oklahoma City. Shepherd formerly was manager of acquisitions in Conoco's Foreign Department. Also, **Leonard W. Heiny** has been promoted to assistant regional geologist in Conoco's Rocky Mountain Region. Heiny was a staff geologist in Houston and will now make Denver his headquarters.

Robert L. Gillis has been appointed assistant to executive vice president **Robert C. Gunness** of **Standard Oil Company (Indiana).**


Air controls at choice of three positions
Optional spudder
Optional telescoping or non-telescoping mast
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Optional rotary drive
Optional reverse on rotary drive
Optional colors
Optional hydraulic tong drive with air-tube clutch
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Men in the industry

M. R. Bridgeman

Maurice Richard Bridgeman has been appointed chairman of **The British Petroleum Company Ltd. J. M. Pattinson** has been elected deputy chairman. It is intended to appoint **M. A. L. Banks** to fill the vacancy on the board of directors caused by the retirement of **Sir Neville Gass.**

John Knudsen, Jr., elected to the board of directors, and has been appointed to the position of general manager of **Kent Petroleum Corporation.** Also, **Jess Davy** has been elected to the board of directors of Kent Petroleum.

G. E. Burpee, manager of **Shell Oil Company's** Houston area Production Department, has become assistant to the vice president in Houston. **W. R. Lund** succeeds Burpee as manager of the Houston area Production Department. Lund held the same position in New Orleans.

Martin Russo of McAllen, Texas, has been named regional geologist in **Sun Oil Company's** Southwest Production Division at Dallas. He replaces the retired **Charles H. Row.** Russo will be succeeded as district geologist in McAllen by **Robert Layden**, formerly assistant district geologist.

L. E. Graham, western region land superintendent, Los Angeles, for Continental Oil Company, has been promoted to the newly created position of special representative for the region's Exploration Department. Other promotions include **Hanes M. Dawson,** Fort Worth, assistant land superintendent, southwestern region, promoted to western region land superintendent, and **L. L. Dodds,** Los Angeles, assistant land superintendent, western region, promoted to the newly created position of regional title supervisor for the western region.

Dean P. Guerin and **Robert L. Shick** have been elected to the board of directors of **Petroleum Technologists, Inc.**

F. R. Dykstra has been appointed chief geologist for **West Canadian Oil & Gas Limited.** Dykstra succeeds **J. K. Bryant** who has left the company.

George C. Palmer has been appointed assistant to the president of **Butler Johnson, Inc.,** oil and gas drilling contractors, of Shreveport, La. Palmer was formerly production and reservoir engineer for Southwest Natural Production Company of Shreveport, with whom he was associated with for 14 years.

G. C. Palmer

Emmons Sebenius has been appointed manager of lands for **State Exploration Company's** Gulf Coast region. He will make his headquarters in Lafayette, La.

Bob Stuard has been elected a vice president of **Coral Drilling Company.** Other officers elected are: **Ted Weiner,** president; **Marvin Miller,** vice president; **Tom Weymouth,** vice president; **Bob Kellerman,** secretary, and **Bob Johnson,** secretary.

J. M. Zachary has been elected president of **Neville G. Penrose, Inc.,** oil production firm of Fort Worth. Other officers elected were: **John P. McNaughton,** executive vice president, the post evacuated by Zachary; **Glenn G. Neill,** elected assistant vice president; **Clem L. Ware,** elected assistant to the vice president; **J. L. Tatum** was named a director, and **Neville G. Penrose,** who has served as president since 1936, has assumed the duties as chairman of the board.

D. C. Wimberly has transferred from **Standard Oil Company of California, Western Operations, Inc.,** to **California Research Corporation,** San Francisco, and has been appointed as technical assistant to the vice president, Petroleum Products Research Department.

OILFIELD TRUCK AND FLOAT

Thornycroft Sandmaster 252" wheel base Oilfield Truck. Hands-England full Oilfield Body. 60,000 lb. winch, heavy duty gin poles, winch operated gin pole risers and folding SAE king pin.
Hands-England 75,000 lb. capacity, tandem axle Oilfield Float 30' 0" long and 9' 6" wide, folding support legs and inverted 36" fifth wheel.
Truck and Float on Michelin 18.00 x 25. Sahara "X" sand tires.

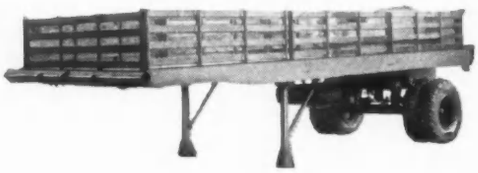
OILFIELD TRANSPORTATION EQUIPMENT

OILFIELD FLOAT

Hands-England 75,000 lb. capacity tandem axle Oilfield Float 30' 0" long and 8' 6" wide, folding support legs and inverted 36" fifth wheel.
Float on 11.00 x 20 — 14-ply tires.

OILFIELD TRUCK AND FLOAT

Scammel Constructor 261" wheel base Oilfield Truck.
Hands-England 75,000 lb. capacity tandem axle Oilfield Float 30' 0" long and 9' 6" wide, folding support legs and inverted 36" fifth wheel.
Truck and Float on 14.00 x 20—18-ply tires.



OILFIELD FLOAT

Hands-England 25,000 lb. capacity single axle Oilfield Float 24' 0" long and 8' 0" wide, folding support legs and SAE king pin 11.00 x 20—12-ply tires. Steel stake sides.

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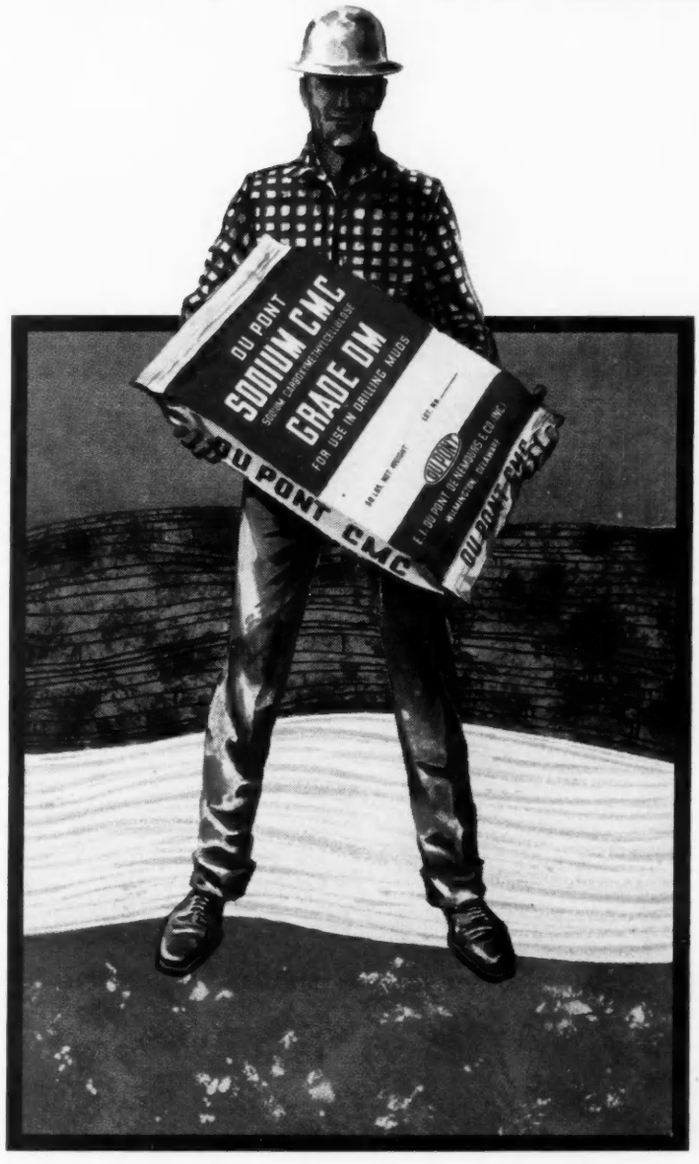

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Men in the industry

James R. Murray, Winnipeg, Manitoba, and **Milton Foley,** Vancouver, British Columbia, have been appointed directors of **Hudson's Bay Oil and Gas Company Limited.** Hudson's Bay is an affiliate of **Continental Oil Company,** Houston, and **Hudson's Bay Company,** Winnipeg.

R. S. Terry has been named area land agent in **Shell Oil Company's** Houston area office. He will be succeeded in his former position of Houston Division land manager by **J. W. Baumgardner,** who has been working as a land man in the area office.

Associations

Oil Producers of California Re-Elect Von Hagen President

Richard R. Von Hagen was re-elected president of Oil Producers Agency of California at the annual meeting of the independent oil producers association's Board of Directors. Von Hagen is president of Lloyd Corporation, Limited.

Vice presidents re-elected were: H. D. Campbell, president of Franco-Western Oil Company, and John H. Matkin, vice president of Kern County Land Company. Newly elected vice presidents are Lee S. Osborne, vice president of Union Pacific Railroad Company, and C. G. Williams, vice president of Universal Consolidated Oil Company.

Ross McCollum, president of National Oil Company was re-elected secretary-treasurer, and T. D. Bonney, president of Mt. Diablo Co. was elected assistant secretary-treasurer. Stark Fox was re-elected executive vice president.

Directors re-elected are: Campbell; J. M. Feldman, president of Golden Bear Oil Company; Robert H. Garrison, Manager of Hellman Estate; H. E. Rickard, vice president of Intex Oil Company; Von Hagen; Charles T. Wilson, president of The Petroleum Company and Roy W. Young. F. M. Cole, vice president of Honolulu Oil Corporation, was elected to fill the unexpired term of L. A. Cranson, resigned.

Henry Kerr Named to Head API's Southwestern District

Henry Kerr, general superintendent of production operations for Delhi-Taylor Oil Corporation, Dallas, has been chosen to head the American Petroleum Institute's Southwestern District for the coming year. Kerr's predecessor as district chairman is L. L. McDonald, The Pure Oil Company, assistant Fort Worth Division manager, who was elected chairman of the district advisory committee. Henry P. Shackleford, Tidewater Oil Company, Hobbs, N.M., was elected district secretary-treasurer.

The election concluded the three-day annual meeting held in Dallas. District vice chairmen elected and their areas of responsibility are: J. W. Sallee, Cardinal Chemical Company, Midland (West Texas); Charles Foster, Gulf Oil Corporation, Wichita Falls (North Central Texas); George Geyer, Cities Service Oil Company, Hobbs, N.M. (Southeastern New Mexico); Al Greer, Benson-Montin-Greer Drilling Corporation, Farmington, N.M. (Northwestern New Mexico); E. C. Mlcak, Standard Oil Company of Texas, Gainesville (Northeast Texas), and C. E. Smith, The Western Company, Lubbock, Texas (South Plains).

As district chairman Kerr will head the planning for the 1961 district meeting.

N. L. Falcon Elected Fellow of the Royal Society

N. L. Falcon, chief geologist of BP Exploration Company since 1952, has been elected a Fellow of the Royal Society.

Falcon joined BP's geological staff in 1927, and was working in Persia until 1936, being resident geologist at Gach Saran when the field was discovered. In 1937 and 1938, he was resident geologist for the exploration drilling program in Scotland and after war service, from 1945 to 1952, was employed as assistant to the chief geologist in head office, with special responsibilities for United Kingdom exploration and photogeological work. In 1952, Falcon received the Murchison Fund Award from the Geological Society of London.

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The JENSEN *Rotary Balanced* JACK is built to work for years and years. It's rugged. Has larger, heavier main shafts and bearings. Taller and more rigid samson post. Simplified installation with complete floor clearance. This JENSEN *R-B* JACK is a work horse that's economical to buy and operate. Get the details on it and other money-making JENSEN JACKS before you buy any pumping unit.

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Forged steel construction — Slip suspension.
Economical — Flexible — Safe.

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Forged steel construction — Slip or Mandrel suspension — for all Slim Hole completions.

NHT TUBING HEAD · 3,000 lbs. test — 1,500 lbs. CWP.
Forged steel construction — Slip suspension.
Full opening — A.P.I. Casing top thread.

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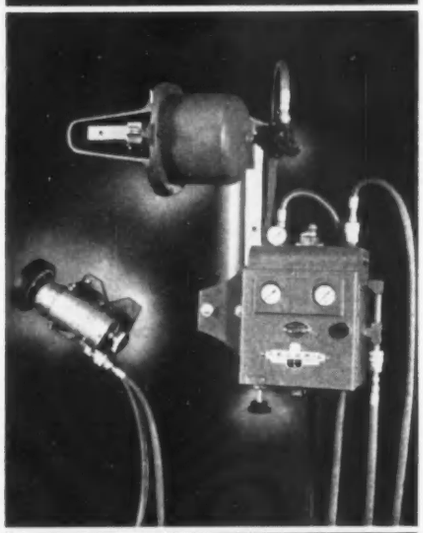
The NEW GEODRIL® AUTOMATIC DRILLER



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Service for the GEODRIL Control is provided by the experienced personnel of Geograph Oil Field Services. Their reputation for service is backed by over a fifth-of-a-century of experience in the oil fields.

When you drill your next well, specify the NEW GEODRIL Automatic Driller for maximum drilling efficiency. For additional information, contact your nearby Geograph Oil Field Services office.

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Suppliers' notes

Zeb Land

Zeb Land has been appointed sales representative at Electra, Texas, for **Bradford Motor Works** of Bradford, Pa. Land was formerly field representative for National Supply Co. at Pampa, Texas, and has over nine years experience in oil pump application and repairs.

Roy F. Cooper, chief engineer of **Sargent Engineering Corporation,** at Huntington Park, Calif., has been appointed vice president, Engineering.

Robert L. Smith is the manager of the new oil field supply store opened recently at Jonesville, Mich., by **The National Supply Company.** The new store is under the jurisdiction of **James A. Gilkey, Jr.,** assistant district manager.

F. A. W. Anger

R. D. Clark

F. A. W. Anger has been promoted to vice president of Manufacturing, and **Robert Duff Clark** has been appointed director of Research and Development for **The Axelson Division of U.S. Industries, Inc.**

Guy E. Lewis has been appointed assistant district engineer, Machinery and Equipment Sales and Service, at Ventura, Calif., for the **Oil Well Supply Division of U. S. Steel Corporation.**

Robert F. (Pete) Holcomb has joined the sales staff of the **Crossett Chemical Company.** He will make his headquarters at the company's general offices in Crossett, Ark.

C. S. Hightower has been appointed field engineer by **Tex-Tube, Inc.,** working out of the Houston headquarters. He will cover the Gulf Coast area. Also, **Jack P. Haden** has been appointed assistant sales manager. He served on the company's sales desk until 1954, when he was appointed outside salesman, a position he has held until his recent promotion.

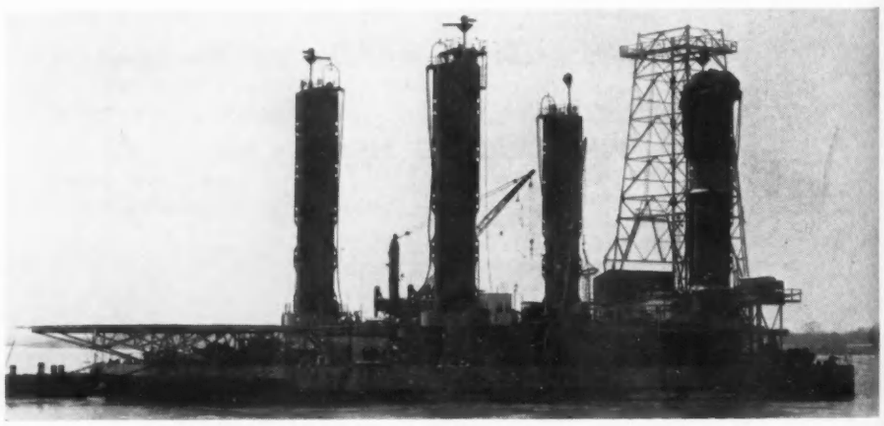
C. S. Hightower

Nobel Sherwood has been appointed technical director of the **Reinforced Plastics Division** of the **A. O. Smith Corporation.**

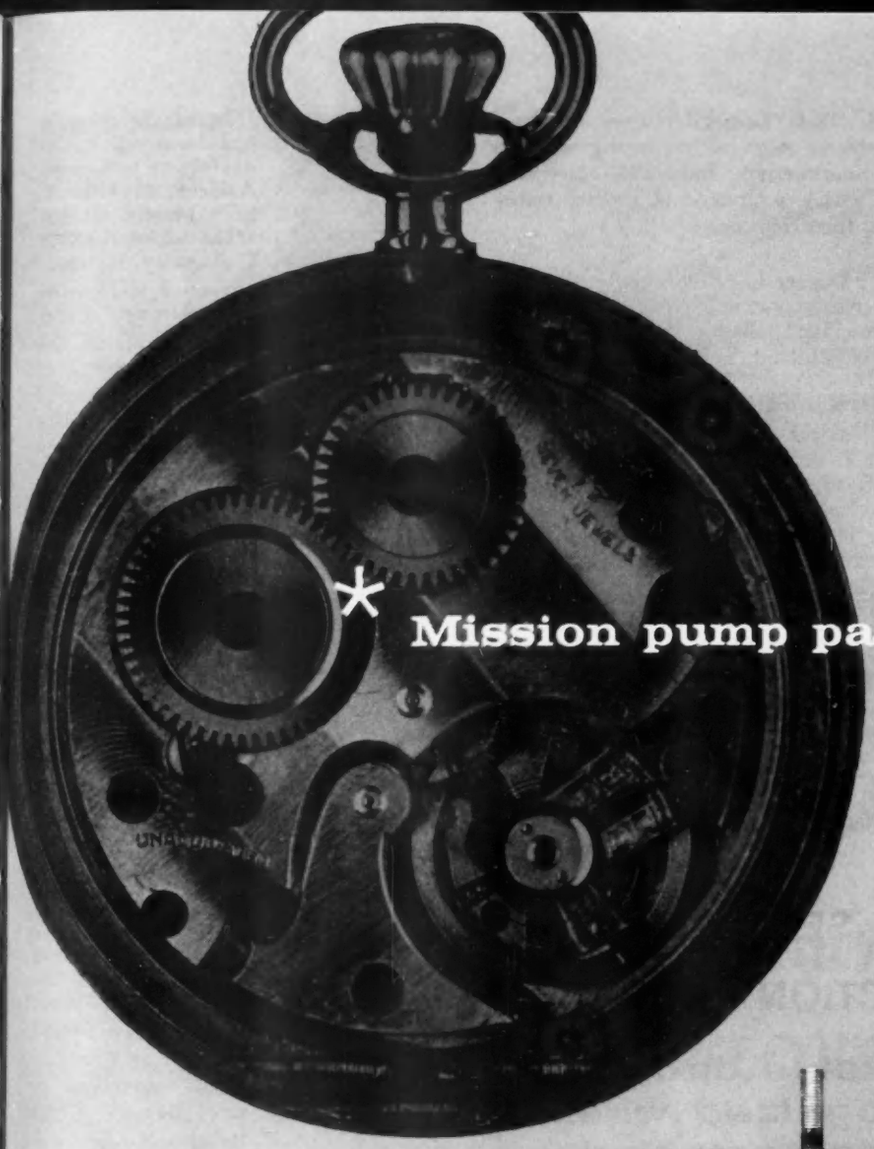
Craig M. Rowley has been elected president of **Parkersburg-Aetna Corporation** following the elevation of **Bernard P. McDonough** to the position of chairman of the board of directors. McDonough continues as chief executive officer.

Anthony Amante has been appointed export sales manager for **Texas Instruments Incorporated Geosciences & Instrumentation Division's Instrumentation Product Group** at Houston.

Charles E. Wright has been transferred to Lafayette, La., where he will represent **Ideco Division of Dresser Industries.**



Sailing Down the Mississippi
The S-66 offshore drilling barge, built by Avondale Marine Ways, Inc., and owned by Barge Facilities, Inc., of San Francisco, moved down the Mississippi River recently to its location in the Gulf Of Mexico for testing. The pontoon has been submerged to the river bottom and the barge is prepared to elevate.



*Mission pump parts work together

MISSION VALVES

MISSION GLAND PACKING

MISSION PISTONS

MISSION LINERS

MISSION LINER PACKING

MISSION PISTON RODS

*SMOOTHLY . . .

From watches to locomotives, mechanical parts work better together when they're designed and built to work together. The same is true for mud pump parts. With the Mission Guarantee you **know** that individually each part—liners, pistons, rods, valves and seats, packing, and springs—will outperform any others. But, when you put them together, allow them to do their best, the savings you get are even greater. And the other side of savings is **your** profit.

When you put Mission pump parts to work you know you're using the best, that's **guaranteed**; but you also are helping yourself the most, cutting your own costs. Start now to stop the waste of shopping around and standardize on Mission all the way.

MISSION MANUFACTURING CO.

MISSION MANUFACTURING CO., P. O. Box 4209, Houston, Texas, cable address "MISSCO" • export office: 30 Rockefeller Plaza, New York • In the United Kingdom: MISSION MANUFACTURING CO., LTD., 1 Hanover Square, London W. 1 England • cable address "MISSOMAN"

68—300

Suppliers' notes

John A. Boatman has been appointed to the position of sales manager of the **Houston Engine and Pump Company's** Harvey, La., Branch. For the past seven years Boatman has been oil field sales representative for a Harvey diesel engine distributor. He also is the author of a series of articles on drilling engines.

J. A. Boatman

E. S. (Bud) Turner has been appointed Northwest Regional marketing manager for **Southwestern Industrial Electronics Co. (SIE), a Division of Dresser Industries, Inc.,** Houston.

B. F. Dugger has been appointed manufacturer's representative for **Herb J. Hawthorne, Inc.,** Houston. Dugger will work out of Midland, Texas.

L. H. Ralston has been named to cover the Dallas-Fort Worth area and part of Oklahoma for **Atlas Pipe, Inc., a Division of Hardy-Griffin Engineering Corporation.** Ralston will operate out of the Atlas Pipe Houston office.

H. S. Gleason

Howard S. Gleason has been appointed assistant to **George A. Peck,** president, **Southwestern Industrial Electronics Company.** Gleason came to SIE from Stromberg-Carlson where he served under Peck there as assistant general manager of the Electronics Division.

Edgar Lea Carter has joined **Mission Manufacturing Company** as sales representative for the Houma, La., area. He will sell and service Mission oil field equipment in the surrounding area of southern Louisiana.

Walter E. Yedlinsky has been appointed by **The Briggs Filtration Company** as representative for industrial sales in the western Pennsylvania area.

Charles F. Gallagher has been named manager of the North Louisiana Division for **Schlumberger Well Surveying Corporation.** He will headquarter in Shreveport. Other promotions and field reassignments include: **F. D. Whitman,** general field engineer at Wharton, Texas, promoted to sales engineer at that location; **C. G. Griffin,** sales engineer at North Louisiana Division, transferred to Columbia, Miss., and promoted to location manager; **L. V. Turner,** general field engineer at Mt. Carmel, Ill., promoted to sales engineer; **D. D. Fitzgerald,** field engineer - Special Services, Gulf Coast Division, transferred to Houston as sales engineer; **H. C. Robinson,** formerly sales engineer, Houston, promoted to location manager at Beaumont, Texas; **G. M. Lehertz,** sales engineer at Tyler, Texas, promoted to senior sales engineer, and **J. A. Gilreath,** senior sales engineer for the North Louisiana Division, transferred to the South Louisiana Division at New Orleans.

C. F. Gallagher

Jack A. Chantrey has been elected treasurer of **Bucyrus-Erie Company.** He succeeds **V. C. Studley** who continues as vice president in charge of finance. All other officers were re-elected.

Joseph A. Wiendl has been appointed general manager of sales for **Ingersoll-Rand Company.** Wiendl was assistant general manager of sales.

Henry K. Coombes has been named field representative for **Skinner Brothers Company** in the Permian Basin Area. Coombes fills the position vacated by **Earl McGill,** who was promoted to assistant to the director of sales.

NEW BULLETIN

CAMCO Announces

WIRELINE SERVICE TOOLS-PRODUCTION EQUIPMENT

available through all recognized wireline service companies...

WIRELINE SERVICE TOOLS:
Rope Sockets
Stem
Jars
Knuckle Joints
Paraffin Cutters
Swages & Gauges
Tubing End Locators
Bailers
Running & Pulling Tools
Circulating Plugs
Perforator Stops
Equalizing Prongs

SUB-SURFACE PRODUCTION EQUIPMENT:
Landing Nipples
Locks
Sidedoor Equip.
Separation Tools
Sliding Sleeves
Magnaset Equip.
Slip Locks
Safety Valves
Blanking Plugs
Bottom Hole Chokes
Equalizing Subs
Standing Valves
Tubing Packoffs

The bulletin illustrated at left describes the complete line of CAMCO Wireline Service & Production Tools now available for use by all recognized wireline service companies. All tools are illustrated and described in this fact-filled bulletin. Operators will find the section on Sub-Surface Production Equipment a MUST. For operational information and catalog data on the newest production equipment from CAMCO . . .

. . . ask your Camco representative for a copy . . . or write:

CAMCO INCORPORATED

C605

P. O. BOX 14484 • 7010 ARDMORE STREET • HOUSTON, TEXAS

Suppliers' notes

William H. Flynn has been appointed general manager of **Electro-Technical Labs Division of Mandrel Industries, Inc.** Flynn succeeds **E. F. Florian** who has been given a special assignment in Burbank, Calif., with **MEG Products Division** of Mandrel.

Arthur F. Baker has been named comptroller of **W-K-M Division of ACF Industries, Inc.** He succeeds **C. M. White, Jr.,** who has transferred to the comptroller's staff of ACF in New York.

Sidney A. Schuman, general manager of the **Fluid Packed Pump Company Division** of **The National Supply Company,** has been transferred to Pittsburgh, Pa., as assistant to the president of National Supply. This is a new position. **James M. McFadden** has been appointed general manager of Fluid Packed Pump replacing Schuman.

S. A. Schuman

T. D. Bruce has been appointed store manager for **Jones & Laughlin Supply Division** at El Dorado, Kan.

James H. Bews has been appointed manager of **Clark Bros. Company's** San Francisco Branch. Bews will be responsible for the sale of Clark engines, compressors and gas turbines in the San Francisco and Pacific Northwest areas.

Charles D. Crickmer has been promoted to chief engineer of the **Baash-Ross Division of Joy Manufacturing Company.** Crickmer was assistant chief engineer in charge of engineering activities at the Baash-Ross plant in Houston.

Niagara Screens Renamed Niagara Screens and Plant Ltd.

Niagara Screens and Plant Limited is the new name of the firm formerly known as Niagara Screens (Great Britain) Limited. The name change was coincidental with an enlargement program resulting in more than doubling the manufacturing facilities of the firm at Enfield. Primary products being manufactured for the petroleum industry at this time are all related to drilling mud handling and condition, including line of mud screens, drilling mud tanks, prefabricated and unitized tanks and ditching systems.

V. Zay Smith Associates Announce New Affiliate

V. Zay Smith Associates, Inc., of Denver, and V. Zay Smith Associates Ltd., of Calgary, Alta., have announced the formation of a new affiliated corporation, "Veezay Helicopters Ltd.," with headquarters located in Calgary.

Veezay Helicopters Ltd., is managed by

power on site from the word GO!

Dependable on-the-spot power now comes in the neatest, lightest, set-it-down-and-let-it-run 'package' you ever saw. The skid-mounted Ruston TE gas turbine generating set gives you constant power availability just when and where you want it. It is capable of long periods of non-stop operation. It is self-contained and requires no cooling water. It is simplicity itself to operate and maintain . . . but why not write for full information in our illustrated catalogue No. 9605X?

RUSTON 'TE' 300 kW **GAS TURBINES**

430 b.h.p. at 80°F. amb. temp.

Ruston long-life gas turbines range in powers up to 1260 b.h.p. (80°F. amb. temp.)

RUSTON & HORNSBY LIMITED · LINCOLN · ENGLAND

Associated with Davey, Paxman & Co. Ltd., Colchester

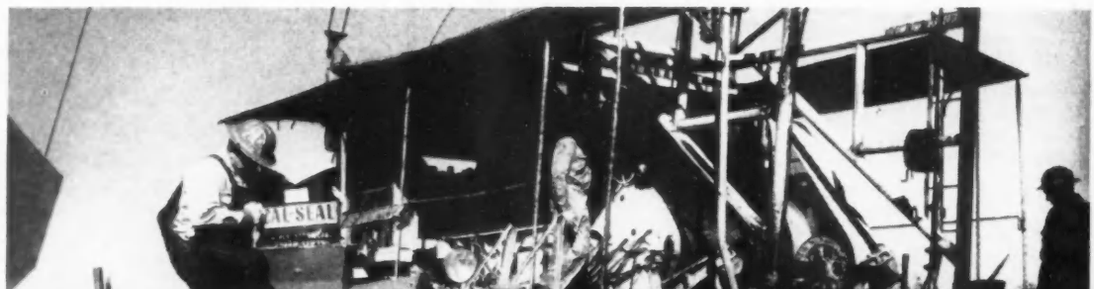
For more data on advertised products, use Readers' Service Cards, last page.

Remedial Time-Saver

Cost of running in strings of drill pipe or tubing is saved when you have remedial cementing done by . . .

HALLIBURTON'S

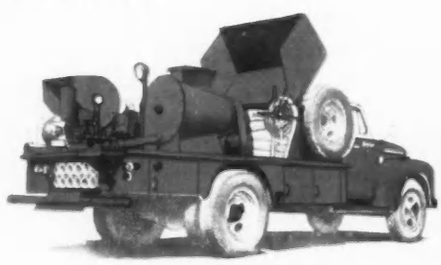
dump bailer service



. . . because bailer containing cement is run in and out of hole on wire line . . . faster, more economically.

Wherever amount of cement needed is not too large and well is not too deep for bailer placement, save money by cementing with "no strings" of drill pipe or tubing. Call the world's most experienced Dump Bailer cementers.

This truck is one of the fleet of Halliburton Dump Bailer units. It carries all materials and equipment needed for Dump Bailer jobs such as . . .



- Nitroglycerine shot tamps
- Plug back jobs
- Bridge in pipe for repairs
- Water shutoff
- Securaloy removal
- Bridge for uphole treatments

HALLIBURTON

COMPANY • DUNCAN, OKLAHOMA

Suppliers' notes

Richard L. Hughes who is also executive vice president of V. Zay Smith Associates Ltd., consulting geologic firm.

In addition to helicopters, the new company has surface transportation and camp gear, all for use in logistics problems mainly of northwestern Canada and Alaska. The new company is currently operating chiefly to meet the needs of the parent companies, but, is also available for contract services.

Independent Supply Store Opened in Four Corners

Supply Center of Farmington, N. M., is the newest independent oil field supply store for the Four Corners area. Located on South Lake, it is only a few blocks past the new Bisti Bridge across the San Juan River, southwest of Farmington.

According to Art Parr, Supply Center's manager, the store handles equipment and supplies for both rotary and cable tool drilling equipment. The store's slogan "Oil Field Names You Know," refers to well-known names, as well as major drilling bit manufacturers whose products are featured by the store. All types of brand well-head equipment, from needle valve to a complete Xmas tree assembly, are also available.

Continental-Emsco Opens New West Texas Building

Continental-Emsco Company recently opened a new shop building for the reconditioning and assembling of used equipment at the firm's Odessa, Texas, used equipment depot.

The 46 foot x 100 foot steel building is equipped with a 7½-ton electric hoist which travels the length of the building, a heated vat, stationary steam cleaner, hydraulic press and electric grinder. Also active in readying the used equipment for sale is a Series 28 white gin pole truck, trailer-mounted arc welder, portable spray painting outfit with compressor and portable sand blasting machine which are all located in the Odessa depot yard.

Other C-E used equipment depots are located at Morgan City and Shreveport, La. Stocking points for used equipment are in Oklahoma City, Ellinwood, Kan., and Casper, Wyo.

A. O. Smith's 'Shirt Sleeve' Sales Meeting

Area sales managers of the Smith-Erie Division of the A. O. Smith Corporation recently held a "shirt sleeve" sales meeting at the company's Erie, Pa., headquarters. Discussions covered sales, engineering, manufacturing and research. Seated at the foot of the table is H. D. (Buz) Leisenring, director of marketing. Seated at the right is Robert F. McGinn, vice president of Research and Development. Standing at the extreme right is H. G. Smith, manager of the Smith-Erie division.

Gardner-Denver Appoints Distributor in Venezuela

Oil Field Sales and Services, S.A., in Maracaibo, Venezuela, has been appointed a distributor for Gardner-Denver oil field equipment.

Main offices and warehouse facilities are in Maracaibo. Modern service and repair shops and warehouse facilities in Tia Juana and Anaco, have been planned for efficient distribution and service of Gardner-Denver equipment to oil fields in Eastern and Western Venezuela.

Paul Koester is president, and Jerome C. Kearby, vice president of Oil Field Sales and Services, S.A., a subsidiary of U.S. Industries, Inc.

Tyson Smith Company Opens Laurel, Miss. Facilities

The Tyson Smith Company recently opened new warehouse and office facilities at Laurel, Miss. The new combination warehouse-office plant will stock, distribute and service a wide range of oil and gas process equipment.

C. D. McDonald has been named as the district manager for the new location. McDonald has been associated with Halliburton Well Service Company, Spartan Tool and Service, Rector Well Equipment Company and Welex Jet Service.

Drilling & Service Expands Facilities in Southwest

Drilling & Service, Inc., has announced plans for the expansion of its sales and service facilities in the Southwest.

The company, located on the North Central Freeway in Dallas, plans to broaden their Louisiana-Mississippi services and Gulf Coast coverage with a regional headquarters in New Orleans, located in the new Oil & Gas Building.

R. D. Oliver has been named division manager in charge of the New Orleans office. At the same time, James Cowan was appointed Oklahoma Division manager.

A TALE OF TWO FLOODS

HOW TWO WATERFLOOD OPERATORS INCREASE RO

CASE NUMBER ONE

This major oil company, operating a shallow waterflood unit, was experiencing severe declines in some producing wells.

In 1956, five wells were fractured. Production increases were so encouraging that the fracturing program was continued. Results have been analyzed only through 1958, but recent experiences have been at least as good or better than earlier results.

During the three years under study, 52 producing wells were fractured by Dowell and 6-month tests were obtained.

Production before fracturing averaged 2.1 bopd for all 52 wells. Six months after fracturing, production averaged 19.5 bopd—an average increase of 17.4 bopd or a percentage increase of about 930 per cent.

In addition to the producing wells, many injection wells were also fractured so that increasing volumes of water could be handled with a minimum addition of wells and pumping equipment.

Three-month reports are available on 20 such injection wells. Before fracturing, the wells would take an average of 44 bwpd at line pressure. Three months after fracturing, they would take an average of 202 bwpd—a 4.6-fold increase.

No exact monetary value can be placed on this increase, but it is obvious that the system could handle more water without increases in equipment and power requirements.

CASE NUMBER TWO

This independent operator started flooding a Bartlesville sand pool that had been abandoned. The field was originally opened up in 1917 and had been depleted by primary methods.

Early in the flood, the operator found that conventional five-spot flooding of the central part of the pool did not yield economical production. A general policy was developed to inject water in the central part and drill producing wells around the periphery.

Apparently there was still considerable oil in place along the edges, but the relatively tight formation prevented profitable producing rates without fracturing.

In 1952, the first two fracturing treatments were performed. Results were so encouraging that a systematic program of drilling and fracturing was started. By

THE STORY AT A GLANCE

- Location — **Eastern Kansas**
- Operated by — **a major oil company**
- Number of fracture treatments — **52**
- Average production per well before fracturing — **2.1 bopd**
- Average production per well **six months** after fracturing — **19.5 bopd**
- Average per cent increase in production — **930 per cent**
- Approximate cost of all treatments — **$27,000**

MORE IDEAS FROM DOWELL

TO HELP INCREASE PROFITS FROM SECONDARY RECOVERY

MAGNESIUM PELLETS

are often pumped into the formation before acidizing to heat the acid and melt away heavy hydrocarbons that might be blocking either injection or production. These treatments have proved remarkably successful.

ROCKSHOCK*

(Implosive formation treating service) is proving valuable both for formation cleaning and fracture initiation. It often makes possible the fracturing of formations that could not otherwise be fractured.

EZEFLO*

is a new Dowell surfactant. Available in bulk, it is especially useful for lowering water injection pressure. It is suitable for any use where an efficient, concentrated anionic surfactant is indicated.

SE ROFITS WITH DOWELL STIMULATION SERVICES

THE STORY AT A GLANCE

- Location — **Eastern Kansas**
- Operated by — **an independent producer**
- Field had been abandoned before waterflood started
- Number of fracture treatments — **34**
- Cumulative production from fractured wells* — **866,512 barrels**
- Cost of fracturing* — **$25,828**
- Fracturing cost per barrel of oil — **3 cents**
- Fracturing cost as a percentage of total production cost — **less than two per cent**

*to December 31, 1959.

the end of 1959, 34 frac jobs had been performed at a total cost of approximately $25,828. All but a few of the earlier jobs were performed by Dowell.

Fracturing fluids, sizes of jobs and techniques were modernized and improved, as the program continued, to assure the operator of the greatest possible return on his investment.

Cumulative production from these wells totaled 866,512 barrels by the end of 1959. The net sales price of the oil was in excess of two million dollars. Cost of the fracturing treatments amounted to 3 cents per barrel of oil produced or less than two per cent of the total cost of producing the oil.

For this two per cent, the operator changed a flood that was headed for economic failure into an excellent financial success.

These field studies are just two more examples of how Dowell services can help operators improve production, keep down costs, improve profits and speed payout on investment.

You may run into a wide variety of problems in addition to oil production when you operate water disposal, gas injection or waterflood facilities. Your Dowell representative has a wide variety of services and products—both new and old—to help you solve your problems. A few examples are noted in the box below.

In addition to those services mentioned here, Dowell offers the Frac Guide*, the Acid Guide*, Cealment*, Corban* and Freflo* to help solve problems of secondary recovery. For more information on how Dowell can help you increase profits from your secondary recovery, pressure maintenance, water disposal or gas injection projects, **dial Dowell.** Dowell services and products are available from more than 150 offices and stations in the United States, Canada, Venezuela, Argentina and Germany. Dowell, Tulsa 1, Oklahoma. *Dowell Trademark

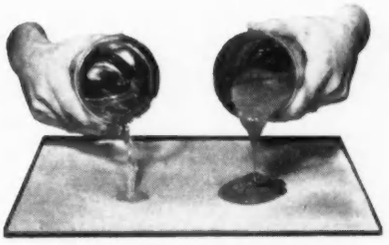
Services for the oil industry

DOWELL

DIVISION OF THE DOW CHEMICAL COMPANY

ABRASIJET*

(Dowell-developed abrasive jetting service) can be used to initiate fractures, perforate or clean the formation face. On injection or disposal wells the result is often a good increase in receptibility and/or a lower injection pressure. On producing wells, the results have been higher production, better gas/oil or oil/water ratios or improved results from fracturing or acidizing.



STABILIZED ACID

is regular acid with a special addition agent to prevent the deposition of gummy iron or aluminum hydroxides which might otherwise plug formation pores.

GYPBAN*

is a Dowell agent that is used to prevent formation plugging by water-formed gyp deposits. It is oil-insoluble and dissolves only gradually in water, thus providing months-long protection.

Suppliers' notes

Applied Power to Distribute Continental Motors Products

Applied Power Equipment & Manufacturing Company has been appointed distributor of Red Seal Engines by Continental Motors Corporation. Stocks of engines and parts will be maintained in Houston and Alice, Texas. Mechanical services will be provided for users of Red Seal Engines on an around-the-clock basis from these locations.

Applied Power will continue to sell and service their regular line of engines along with a complete line of necessary items as in the past. There will be no major changes in sales policy, operating procedures, or personnel as a result of this expansion.

Continental-Emsco Purchases Win-Well Manufacturing

Continental-Emsco Company recently purchased the Win-Well Manufacturing Company of Tulsa. Included in the purchase were patents, inventory, jigs and fixtures for production of the Win-Well Rotary Selector Valve.

The valve now will be known as the Win-Well Green Triangle Rotary Selector Valve and will be manufactured at Continental-Emsco's Garland, Texas, plant.

Tulsa Winch Undergoes Slight Name Change

Tulsa Winch Division has announced a slight variation of name changing for the firm. The firm, formerly known as Tulsa Winch Division, now is known as Tulsa Products Division, Vickers Incorporated, Division of Sperry Rand Corporation.

Officials of the company stated that the former name had lost much of its descriptive meaning because of the expanded line of "Tulsa" products. Also, according to company officials, the firm will have new engineering, sales and purchasing offices located immediately west of the plant.

Alberta Tool To Manufacture Larkin Packer Equipment

Alberta Tool Company, Ltd., Edmonton, Alta., and Larkin Packer Company, Waxahachie, Texas, a Division of Koehring Company, have entered into an agreement whereby Alberta Oil Tool will manufacture certain items of Larkin oil field equipment in its Edmonton shop for consumption in Canada. The announcement was made recently by E. M. Blanchard, president of Alberta Oil Tool Co., and W. H. Larkin, president of Larkin Packer Company.

According to the announcement, both companies will retain their separate entities. Also, the new combine would start marketing Canadian-made materials in a small way immediately, and that over a period of years, Larkin Packer Company would perhaps have some of its entire line made in Canada. Larkin standards and quality will be adhered to in all Alberta Oil Tool manufactured items.

Southern Engine & Pump Adds New Engine Line

Southern Engine & Pump Company, Houston, has been appointed distributor for Minneapolis-Moline Company's oil field engines. The territory assigned includes the eastern half of Texas with its western boundary on a line between Gainesville, Waco and Del Rio, and the western half of Louisiana.

S. R. Carrington, president of Southern Engine, reports that his company will handle sales and service of Moline oil field units at Houston headquarters and at branches. Branch officials and locations are: In Texas, W. A. Courreges, manager, Dallas; O. A. Johnson, sales engineer, Kilgore; H. R. Townsend, manager, San Antonio; O. B. Vincent, manager, Beaumont; J. E. Kelly, manager, Corpus Christi; In Louisiana—C. J. Uthoff, manager, New Orleans; E. W. Boswell, manager, Shreveport.

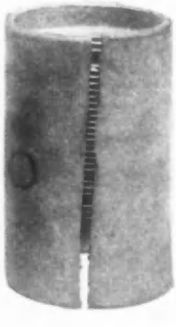
Officers of Southern Engine & Pump Company are: C. A. Leavens, chairman of the board; S. R. Carrington, president; H. A. Reinholt, secretary and office manager, and G. I. McMakin, treasurer.

Southern Engine will sell these Moline power units equipped with generators, compressors, pumps, etc. for oil field applications.

Problem:

Solution: (2 POSSIBILITIES)

Bad, expensive solution: Run tubing in well. When string parts, fish out, remove bad coupling. Measure cost in time lost, extra equipment, possible loss of well, ulcers.



Inexpensive UNISCO solution: Have UNISCO perform magnetic particle inspection on all tubing couplings. Discard bad couplings. Measure cost at 15¢ per coupling.

Evaluation of problem and solutions: Call your nearest UNISCO office for full particulars on all inspection and service work on your tubing.

NOW! All tubing couplings which Hardy-Griffin modifies to GT-API specifications are given a magnetic particle inspection by UNISCO without additional charge!

For UNISCO *Teleflaw** service, contact

UNIVERSAL INSPECTION & SERVICE CO.
A DIVISION OF ATLAS PIPE INC.

Houston—GY 9-9250 • New Iberia—EM 4-8666 • Odessa—EM 6-8241

**Teleflaw*, patented, & patents pending.

SQUEAKS from the BULLWHEEL

"He should use some of that oil—He's so tight he squeaks."

Our Wayward Children

After his first day in school, Junior came home and announced that he was through—would never go back. When his mother asked for an explanation he said:

"Well, I can't read and I can't write and the teacher won't let me talk. What's the use?"

Age of Speed

The man in the big Cadillac had tried for 20 minutes to outdistance the small foreign car that had been traveling behind him.

As he hit 90, the small car drew alongside. "I say," yelled the driver, "Do you know anything about this make car, I can't get her out of low gear!"

Just a Winkin'-an-Blinkin'

Wife: "I saw you winking at the girls down at the corner the other day."

Husband: "I wasn't winking, dear, that's a busy corner and something got in my eye."

Wife: "Got into your car, too!!"

Now, Start Talking

A pair of newlyweds stepped into the hotel elevator.

"Hello darling," murmured the pretty operator.

There was a chilly silence all the way up. But when they reached the floor near the top the young bride exploded: "Who was that hussy?"

"Now don't you start anything," begged the groom. "I'm going to have enough trouble explaining you to her tomorrow!"

The Facts of Life

Reporter: "Tell me, Pop, to what do you attribute your longevity?"

Retired Truck Driver: "Well, it's this-away, sonny. I never waste no energy resisting temptation!"

All For One—One For All

Captain: "Will the soldier who sneaked out after bed-check last night to meet a girl in the woods please step forward . . . company . . . halt!!"

Sometimes You Can't Win

"May I have another cookie?"
"Another cookie what?"
"Another cookie, please."
"Please who?"
"Please, Mother."
"Please, Mother what?"
"Please, Mother dear."
"No, you've had six already."

The Perfect Perfect

The trouble with some people is that they won't admit their faults. We'd admit ours if we had any.

Let R-u-b-b-e-r Take The Wear
in your sucker rod pumps

IT COSTS YOU LESS THAT WAY

● MARTIN RUBBER & DUCK RINGS give excellent life in dirty abrasive fluids . . . high or low gravity . . . much or little water . . . shallow or deep wells. They last for years in the easier pumping wells. Replacement rings cost comparatively little.

● MARTIN PLUNGER BODIES, precision grooved, drilled and threaded (no underneath fluid passage), usually last for years. Tube or barrel costs are often cut in half.

● The replaceable SYNTHETIC RUBBER GUIDES in MARTIN CAGES last longer than any metal, and the cushioning of the ball increases your ball & seat life. Results are often truly amazing. (Patent No. 2,591,174)

Write for our new 1960 catalog or see it in the new Composite (24th Edition). All products sold thru supply companies.

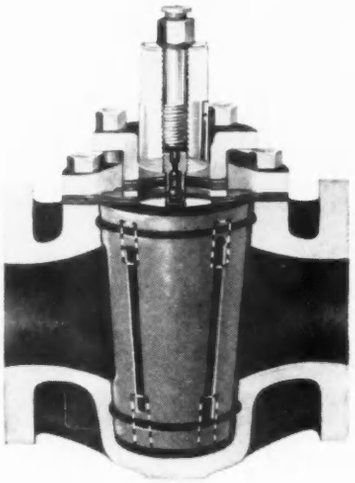
JOHN N. MARTIN
Manufacturer
9 W. BRADY STREET • TULSA, OKLAHOMA

the idea:

Simplicity Is Basic To Efficiency and Economy

One of the world's first valves, plug cocks invented by the Chinese centuries ago, had only one moving part—the plug. Even the earliest craftsman recognized the fact that simplicity of design almost always means a device that works better, lasts longer and costs less to use.

the application:



How It Helps Give You A Better Valve

In the modern Rockwell-Nordstrom lubricated plug valve there are only three rugged, basic parts . . . plug, body and cover. The plug is the only moving part. Compared to other valves, nothing could be simpler or more efficient. Yet the many advantages of simplicity are actually multiplied by *lubrication* in these valves. Pressurized lubrication jacks the plug, keeping it free for instant ¼-turn operation. It also forms an instantly replaceable, impenetrable seal against leakage, and prevents metal-to-metal wear.

the benefits:

Longer Valve Life At Lower Cost . . . Leak-proof Sealing . . . Reduced Down Time . . . Completely Protected Seating

The 6 million Rockwell-Nordstrom lubricated plug valves now used in a wide variety of industries are translating these benefits into dollars and cents savings day after day. Rockwell-Nordstrom is the most complete line of lubricated plug valves (sizes from ½" to 36"; pressures to 15,000 lb), lubricants and operating accessories. For *practical* help in solving your flow control problems, see your supplier or write: Rockwell Manufacturing Company, Dept. 93G, Pittsburgh 8, Pa. Canadian Valve Licensee: Peacock Brothers Limited. If you live outside the U. S. or Canada, write: Rockwell International, S.A., Geneva, Switzerland.

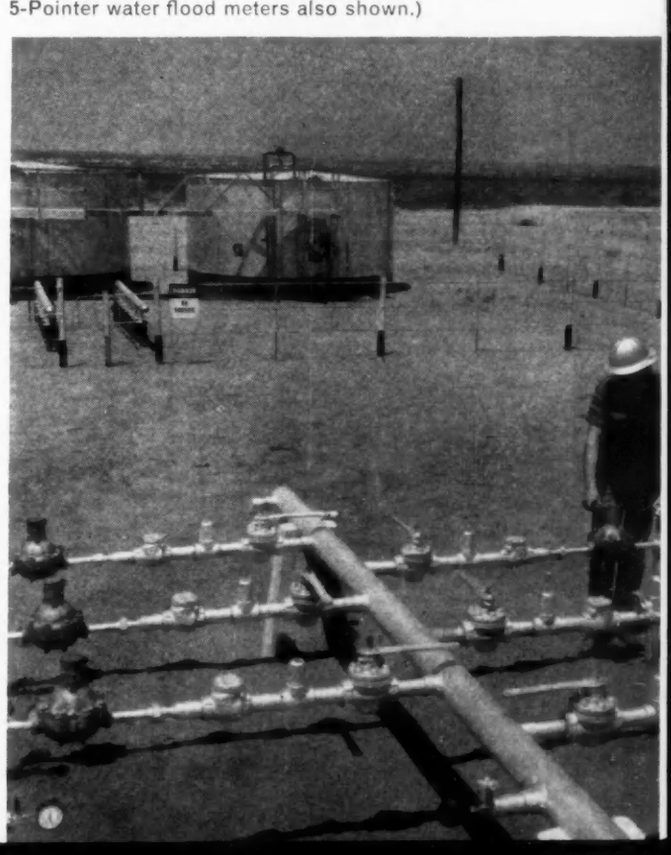
Lubrication Makes The Difference

ROCKWELL-Nordstrom VALVES

another fine product by

ROCKWELL

Rockwell-Nordstrom valves resist punishment of water flooding operations, assure perfect control. (Rockwell 5-Pointer water flood meters also shown.)



Just Being Doubtful

"Boss," said the dock foreman, "the men on the dock are a little leery of the new freight loader you hired yesterday."

"Why so?" asked the terminal manager. "He checked out well."

"Maybe so," replied the dock foreman. "But this morning he stubbed his toe on a crate of iron castings and said, "Oh, the perversity of inanimate objects!"

Attention!

"For the last time," shouted the sergeant, "I ask you a simple question. What is a fortification?"

The recruits remained silent.

In desperation the NCO glared at what he thought the most intelligent looking man and demanded an answer.

"A fortification is two twentifications!"

Big Decisions

If you can't lick them and they won't let you join them—what then?

Time Marches On

"Young man," admonished the girl's father, "at 10 o'clock we turn out the lights."

"That's O.K., sir. We won't be reading."

Life's Like That

"How come you beautiful redheads so often marry men who are feeble, bald, nervous and weak?"

"We don't. They just get that way."

Kind to Dumb Animal Week

The head of a branch of the Society for the Prevention of Cruelty to Animals has just hired a new typist, and he spent an hour explaining the work of the organization and the office routine.

"If you have any questions as you go along, don't be afraid to ask," he told her before returning to his desk.

A few minutes later the girl appeared in front of him. "I have a question," she said. "Is it all right if I swat a fly?"

Getting Smarter Everyday

Son: "I learned to say 'Yes, sir' and 'No, sir' in school today."

Father: "You did?"

Son: "Yeah."

SECONDARY RECOVERY

PETROLEUM ENGINEERS
STEPHENS ENGINEERING
WICHITA FALLS, TEXAS

RESERVOIR ENGINEERING
Water Flooding Gas Repressuring
EVALUATION CORE ANALYSIS
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RATES: Regular Classified (undisplayed) set in this size type: 20 cents per word. Minimum charge $4. Blind box address in our care counts six words. Replies forwarded without charge. **Display Classified ads,** set in suitably larger type with ruled border, $13.50 per column inch. Ten percent discount for two or more insertions of same copy in consecutive issues. **All classified ads payable in advance.** Send copy and checks to: Trading Post Classified Section, World Oil, P. O. Box 2608, Houston, Texas.

HELP WANTED

■ Petroleum Engineer, P.E., M.S., Registered, 28, 5 years experience diversified, waterflood project supt., deal and evaluation work, employed as production supt. for independent in Venezuela. Preference for Latin America, but will consider other opportunities. 2501 Boyd, Ft. Worth, Texas.

Translators-Scientists Wanted

Proven ability to translate technical material into fluent English essential. Attractive full time or free-lance arrangement. All languages of interest particularly Russian and Japanese. Send résumé to: A.T.S. Inc., Drawer 271, East Orange, N. J.

LEASES, DRILLING ACREAGE, ETC.

■ U. S. DEPARTMENT OF THE INTERIOR, Bureau of Land Management, Washington 25, D. C. Notice is hereby given that approximately 1035.51 acres of land within the Naval Auxiliary Air Station, Chase Field, Bee County, Texas, will be offered for oil and gas leasing through competitive bidding to the qualified bidder of the highest cash amount per acre at 1:00 P.M., E.D.T., July 13, 1960, when bids will be opened. Details of the lease offering, how and where to submit bids, may be obtained from the Director, Bureau of Land Management, Department of the Interior, Washington 25, D. C.; the Land Office, Bureau of Land Management, P. O. Box 1251, Santa Fe, New Mexico; the Branch of Oil and Gas Leasing, Geological Survey, General Services Administration Building, Washington 25, D. C.; or the Regional Oil and Gas Supervisor, Geological Survey, Gulf Coast Region, 204 Maritime Building, 203 Carondelet Street, New Orleans, Louisiana. Edward Woozley, Director.

FOR SALE

BUDA POWER UNITS

Unused surplus, new condition. Four Cylinder, 121 HP Gasoline Engines. Complete with radiator. Twin disc clutch and 5 sheave V-belt drive pulley. Can be converted to LP or Natural Gas. Priced at fraction of cost, $1,495.00 each. Photograph and complete specifications on request.

OLDFIELD EQUIPMENT CO.
430 W. Seymour Ave., Cincinnati 16, Ohio

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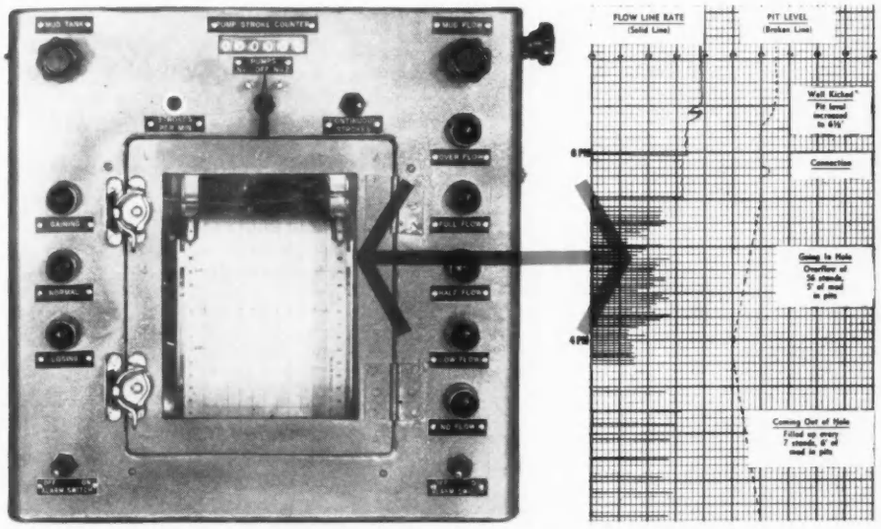
MODERN, ATTRACTIVE OFFICE BUILDING

at 1025 S. Shepherd containing 7500 sq. ft. floor space. Located across street River Oaks and two blocks freeway. Formerly occupied by geophysical company. Situated on 85,000 sq. ft. of valuable land which also contains shop and lab buildings. Ideal for oil company, service company, lab, shop, etc. Sale price $350,000. Call JA 8-5360 or write

Robt. H. Ray, Co.
P. O. Box 6557, Houston 5, Texas

For the latest information on what's new in equipment, turn to Page 167

NEW equipment and services



New Mud Control System

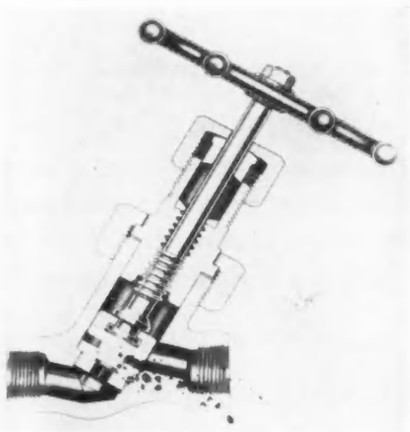
A new mud control system, the Mud Signalite and Recorder, has been developed. This "early warning" instrument reduces hazards of salt water flows, lost circulation, blowouts, etc., by immediately indicating, through visual and audible signals, any change in the mud system.

The unit, which is mounted close to the brake, is composed of a flow line instrument, pit level instrument, recorder and pump stroke counter. All instrumentation is contained in a compact steel case 18 x 18 x 11 inches.

- Driller has constant knowledge of mud flow rate at the flow line as well as pit level.
- Lights and warning horn indicate any major change in mud flow or pit level.
- A complete graphic record of mud flow, pit level, etc., is available at all times.
- Automatic pump stroke indicator counts either for 60 seconds or continuously on No. 1 or No. 2 pump.

The Mud Signalite and Recorder is available at nominal cost on a lease basis. (J & A Special Instrument Company.)

For more data, circle E1 on postcard



Plastic-Coated Valves

Forged steel globe valves with plastic coatings baked on the inside body for waterflooding and other secondary recovery pressure maintenance systems have been made available. Plastic is a special formulation of phenolic, epoxy and other resins that provides corrosion protection against salt and sulfide waters. Coating will not peel or undercut even if it is mechanically broken. (Edwards Valves, Inc., A Subsidiary of Rockwell Manufacturing Co. Supplements data on Pages 1730-1733, 1960-1961 Composite Catalog).

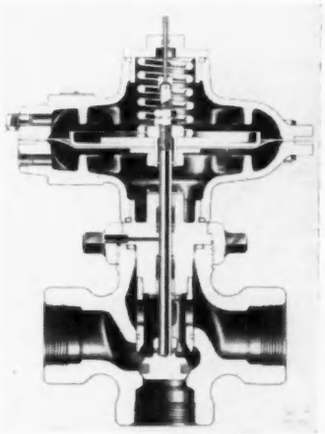
For more data, circle E2 on postcard

New Quintuplex Pump

A new quintuplex pump designed for use in secondary oil-recovery operations is available. The new QPA-5,000 Series quintuplex has a 5-inch stroke with plungers ranging in diameter from 1½ inches to 3¾ inches, and was designed for continuous service capable of 230 bhp when operating at 360 rpm. Pressure rating extends up to 5,150 psi which will meet the most extreme requirements in most waterflood operations. (Ajax Iron Works. Supplements data on Pages 164-167, 1960-1961 Composite Catalog.)

For more data, circle E3 on postcard

CORRECTION



Diaphragm Control Valve

This Type 1,664 three-way, two-position diaphragm control valve, designed for oil production work, has a cast iron body with a 400 psi WOG rating. Is available in the 2-inch size with either screwed or grooved end connections. Body can be converted easily into a single globe or angle body by plugging one of the outlet ports. Spring opposed or pressure balanced topworks are available. Spring opposed topwork is reversible in the field to give fail-open or fail-close action. The manufacturer of this item was listed incorrectly on Page 224, May 1960, World Oil. (Fisher Governor Co. Supplements data on Pages 1837-1846, 1960-1961 Composite Catalog.)

For more data, circle E4 on postcard

New Fluid Loss Agent

Extended fractures and deeper sand penetration with water and acid base fracturing fluids has been announced as possible with WAC-8, a multi-purpose fluid loss agent. Fluid retention properties of this newly developed chemical approximate 20-25 ml in 30 minutes. WAC-8 is compatible with most surfactants used in water or acid

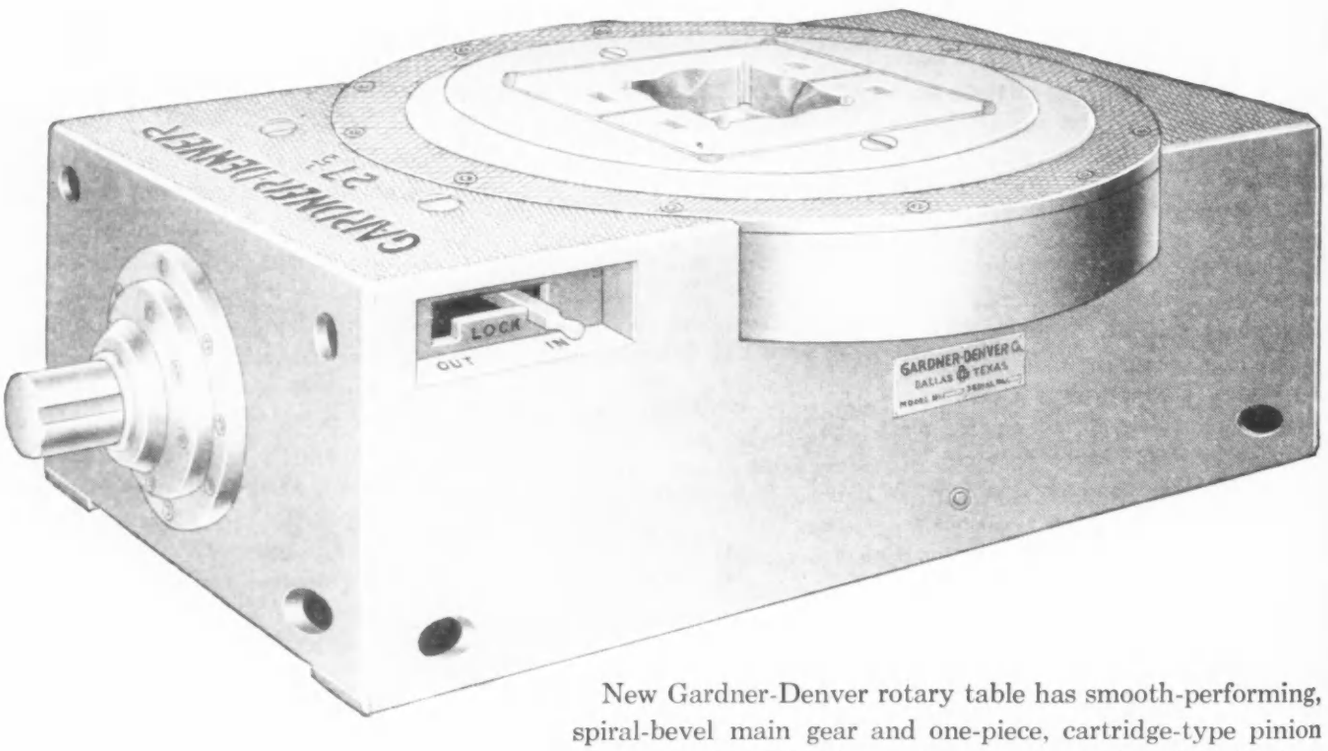
Designed for drilling to 30,000'

500-ton dead-load capacity

Positive mud seals

27½" table opening

New Gardner-Denver rotary table designed for drilling deepest wells



New Gardner-Denver rotary table has smooth-performing, spiral-bevel main gear and one-piece, cartridge-type pinion shaft assembly. Working parts are protected by oil-bath lubrication in streamlined steel housing, and by positive mud seals. Table ratchets left or right, or locks in fixed position. Ask your Gardner-Denver petroleum industry specialist for complete details.

EQUIPMENT TODAY FOR THE CHALLENGE OF TOMORROW

GARDNER - DENVER

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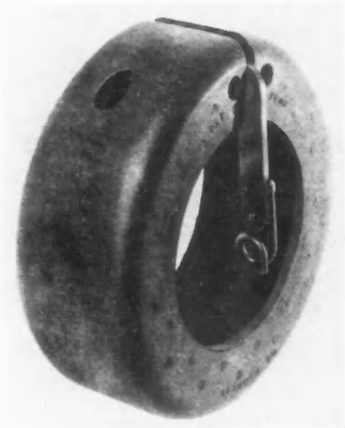
Gardner-Denver International Division, 233 Broadway, New York 7, N. Y.

Petroleum Offices: Casper, Cleveland, Columbus, Corpus Christi, Dallas, Denver, Durango, Edmonton, Ellinwood, Evansville, Houston, Huntington, Jackson, Kansas City, Lafayette, Los Angeles, Mexico City, New Orleans, Odessa, Oklahoma City, Pittsburgh, San Francisco, Shreveport, St. Louis, Tulsa, Wichita, Winnipeg

base fluids. One of the components of WAC-8 helps to destroy its effect after the treatment is completed. (Halliburton Oil Well Cementing Co. Supplements data on Pages 2301-2424, 1960-1961 Composite Catalog.)

For more data, circle E5 on postcard



Casing Thread Protector

This neoprene clamping device, the Klampon Thread Protector, provides protection to the threads of popular sizes and types of oil well casing. Consists of high-strength alloy steel band molded inside an oil-resistant neoprene protector, and an adjustable cam-type latch assembly for manual locking and unlocking of the protector around the external threads of the casing. Protector requires no auxiliary equipment in its operation. (Klampon Corporation).

For more data, Circle E6 on postcard

New Automation Device

A new automation device has been developed for the short or long distance transmission of control and monitoring data. Designed specifically for use by pipe line and production segments of the petroleum industry, it is primarily fabricated of transistors and similar components. It is capable of solving approximately 80 percent of the control problems without any modification whatever. Modification can be achieved by making use of standard "add-on" modules to increase the capacity or the functional capabilities of the system as necessary. (International Controls Corporation.)

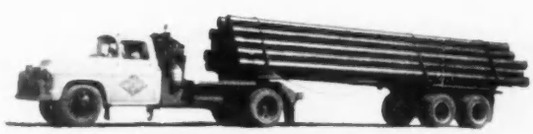
For more data, circle E7 on postcard

Congrats and $25 for this quip to J. P. Denny, Phillips Petroleum Company, Box 1351, Odessa, Texas

Oil and gas men are quick to say that Lone Star products are "tough, top quality and delivered fast". Quick supply, and superior steel are among the reasons more and more have switched to Lone Star API casing, tubing and line pipe.

Exacting quality control combined with years-ahead manufacturing techniques today . . . are your guarantee of API standards in Lone Star pipe. And remember, delivery in the field is a matter of hours.

Neighbor, wherever you are, specify Lone Star and we both get a good deal.



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Lone Star STEEL COMPANY

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DISTRICT SALES OFFICES
912 Republic National Bank Building, Dallas, Texas
Houston, Texas | Midland, Texas | Tulsa, Oklahoma

For more data on advertised products, use Readers' Service Cards, last page.

New equipment

Rotary Drill Bits

Phipps tungsten carbide rotary drill bits for deep hole drilling are now available. Advantages claimed for the bits include: Four jet streams which jet over three-fourths the center of the hole being drilled; jet stream outlets within 2 inches of the face of the hole where jetting action is most needed; jets do not act against the wall of the hole which prevents drilling over-size hole and prevents caving of the wall or hole. (Phipps Drill Bit Company.)

For more data, circle E8 on postcard

Slim Hole Sand Pump

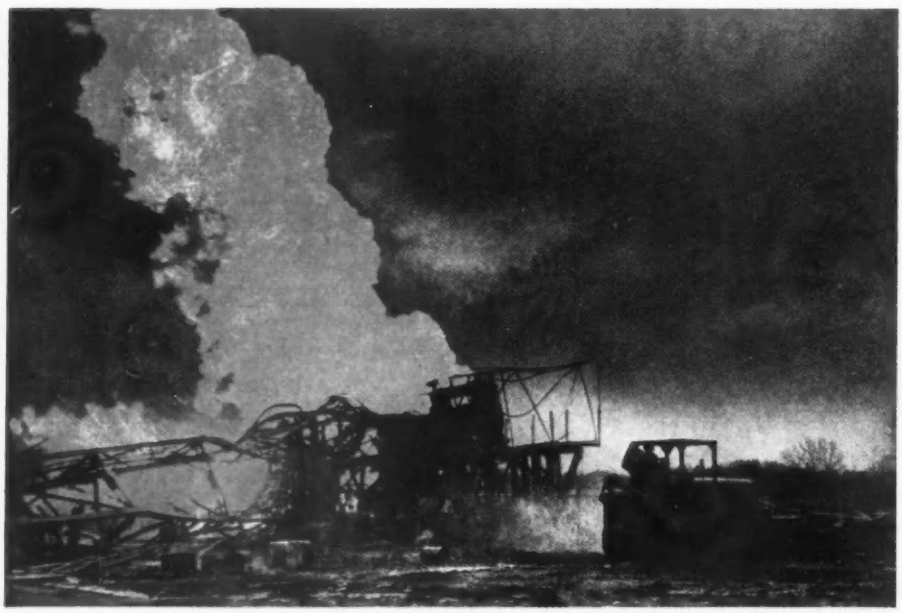
A new slim hole 2-inch OD sand pump for 2⅞-inch OD slim hole completions has been announced. This new sand pump is designed exactly the same as larger Miller sand pumps. The new pump has accurately machined lug-type bottoms. Lengths for the 2-inch pump are 20 to 24 feet. Other Miller Sand Pump sizes are: OD: 2½, 3, 3½, 4½, 5, 5½ and 7 inches. Lengths are 20, 25 and 30 feet for 3-inch OD and larger pumps. The 2½-inch pump is made in 20 and 25 feet lengths. (Miller Sand Pump Company. Supplements data on Page 3688, 1960-61 Composite Catalog.)

For more data, circle E9 on postcard

Fluid-Loss Control Additive

A new, highly improved fluid-loss control additive for cement has been announced. When Flac is mixed into cement slurries, it prevents water in the slurries from escaping into the porous rock in the wall. This keeps cement fluid until it reaches the desired depth, permitting proper placement over a wide range of well conditions and facilitating cementing techniques. Advantages: Flac works as an added retarder in some high-temperature cements and it dry mixes and handles easily. (Dowell, a Division of The Dow Chemical Company.)

For more data, circle E10 on postcard



A "Pit-O-Graf" MIGHT HAVE SAVED THIS WELL

A Pit-O-Graf can give adequate warning to prevent a blowout. But, it must be where the driller can see it, can take advantage of it. Here's what users have to say:

One oil company says — "Although blowout prevention is a matter of concern for the operator, the contractor, and the drilling crews, generally *the driller is the key man.*"

Another company says—"Since a pit level indicator is so important, take these precautions to get the most good out of it: Place the pit level recording instrument at or near *the driller's position on the derrick floor.*"

If the driller's responsibility is not misplaced, then he can recognize the danger signals that precede every blowout. With the Pit-O-Graf record before him, he can intelligently analyze the *rate* of gain or loss of mud as recorded and thereby direct his crew in the orderly control of the situation at hand. In this case the threatened blowout would become *one that does not happen.*

WARREN AUTOMATIC TOOL CO.
3915 THARP STREET • HOUSTON, TEXAS
Phone CApitol 4-2511

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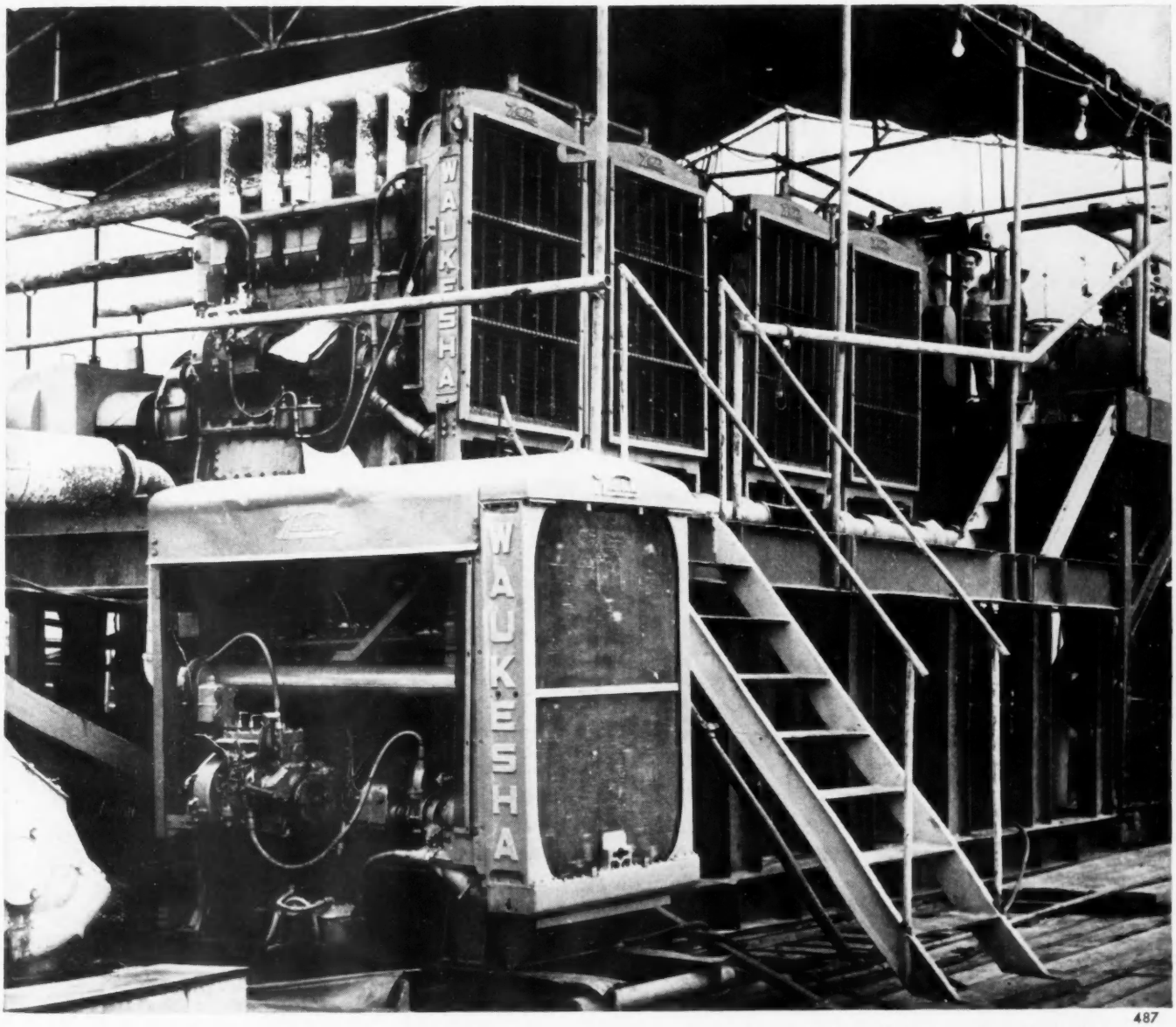
WAUKESHAS

...here and everywhere in the oil fields

The STANDOUTS—in any oil field, on any job—are always Waukeshas! Here, for instance—at Groves, Texas (near Beaumont) on Rig 4 of the Meredith Drilling Co. of Houston, Texas—are four 1905 cu. in., 7 x 8¼-in. NKRBU Waukesha gas power units on the platform; and down below a 1197 cu. in., 6¼ x 6½-in. WAKU Waukesha gas power unit. The driller, H. E. Offutt says these Waukeshas have worked constantly for years with no major repairs. It's that way *all over the oil fields*. Reliability is only one big reason why Waukeshas dominate. Diesel, LPG, natural gas, gasoline—to 1235 hp. Get Bulletin 1079.



487

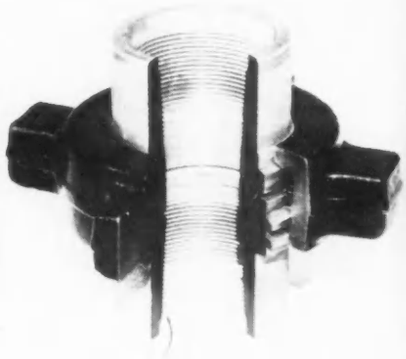
WAUKESHA MOTOR COMPANY, WAUKESHA, WISCONSIN / **New York • Tulsa • Los Angeles**
Factories: Waukesha, Wisconsin and Clinton, Iowa

New equipment

Pumpable Bridging Agent

A pumpable bridging agent in the form of wedge-shaped plugs to greatly increase sealing in large fractures has been introduced. Masterplug mixes readily, and pumps easily through standard mud pumps. Masterplug is highly efficient in bridging because each plug jams against the next plug. Average length of plug is about 2 inches from point to point. Should be used with a lost circulation sealer. (Masterseal Company.)

For more data, circle E11 on postcard



High-Pressure Unions

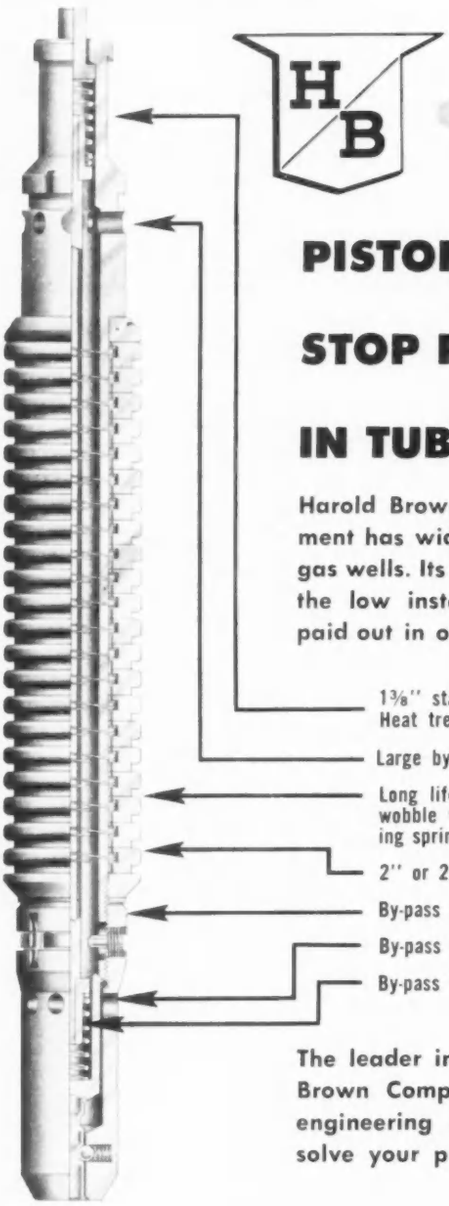
New 4,000 and 6,000 pound working pressure unions with a fast "make-and-break" feature which speeds and simplifies installation and maintenance of pipe line systems are now available. Unions have a full three-pitch acme thread which turns easily, resists being clogged by foreign matter and can be cleaned quickly. The acme thread withstands considerably more physical abuse than a conventional V-thread. (Clayton Mark & Company.)

For more data, circle E12 on postcard

Lower-Pressure Gate Valve

A new lower-pressure gate valve is now available in 2, 3 and 4-inch sizes. It is made of ductile iron, with screwed, flanged and grooved connections, and of steel, with weld-end connections. The new valve, the Demco 1,000 Series Gate Valve, has a 1,000 psi working pressure and a 2,000 psi test. Features include: Ease of operation under pressure, faster opening and closing and a simpler inspection and parts replacement operation. (Drilling Equipment Manufacturing Co. Supplements data on Pages 1657-1692, 1960-1961 Composite Catalog.)

For more data, circle E13 on postcard



H B

PISTONS SEAL EFFECTIVELY, STOP PARAFFIN DEPOSITION IN TUBING

Harold Brown Company *piston lift* equipment has wide application in both oil and gas wells. Its benefits are so numerous that the low installation costs are frequently paid out in only a few months.

- 1⅜" standard fishing neck Heat treated alloy steels throughout
- Large by-pass outlet ports
- Long life hard chrome heat treated steel wobble washers each loaded with a shifting spring
- 2" or 2½" washers interchangeable
- By-pass valve body
- By-pass inlet ports
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The leader in the Piston Lift field, Harold Brown Company offers you the creative engineering and superior equipment to solve your production problems.

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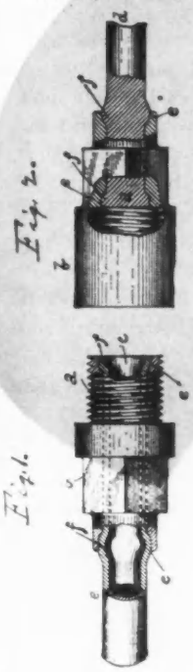
JONES

FIRST IN 1894...

S. M. JONES.
COUPLING FOR PIPES OR RODS.
Patented Oct. 30, 1894.



"Be it known that I, Samuel M. Jones, a citizen of the United States, residing at Toledo, Lucas County, Ohio, have invented certain new and useful Improvements in Couplings for Pipes or Rods, of which the following is a specification."

So reads the opening paragraph of Patent No. 528,168 granted October 30, 1894 . . . this was the beginning of JONES specialization...

FIRST TODAY...

Now, precision is the word for Jones couplings and subcouplings. Made in two finishes..."Soft" and "Hardened and Ground", Jones couplings are finished and quality-controlled to API specifications. For the very finest in low cost oil recovery, continue to use Jones sucker rods and couplings...the products of recognized specialists.

...because we're Sucker Rod Specialists!

There are four
JONES JOB-ENGINEERED SUCKER RODS...
a type for every pumping need!

THE S. M. JONES COMPANY

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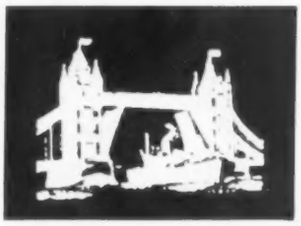

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World-wide facilities through 700 offices in 75 countries

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- The Home Insurance Company
- The Phoenix Insurance Company
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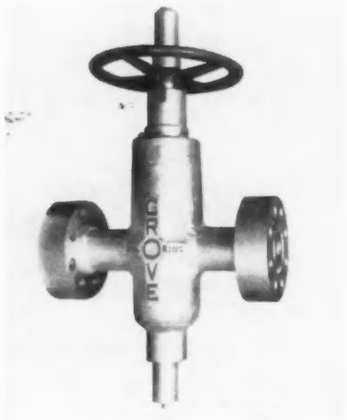
An association of leading American capital stock fire, marine, casualty and surety insurance companies providing insurance protection in foreign lands

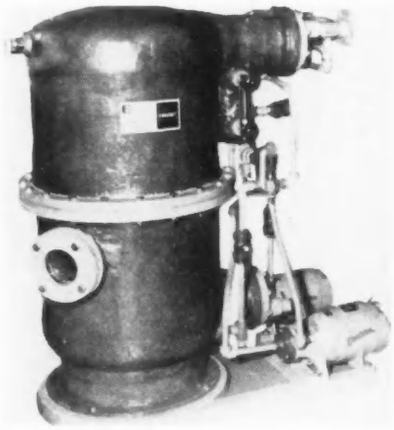
New equipment



Balanced Stem Valve

The balanced stem principle of this new valve for christmas tree and general high-pressure service, calls for a solid stem passing completely through the body, so that the gate can move freely up and down with no end surfaces for line pressure to push against. Valve requires no lubrication and is available in sizes of 1⅝ inches, 1 13/16 inches, 2 1/16 inches and 2 9/16 inches. (Grove Valve and Regulator Company. Supplements data on Pages 2253-2260, 1960-1961 Composite Catalog).

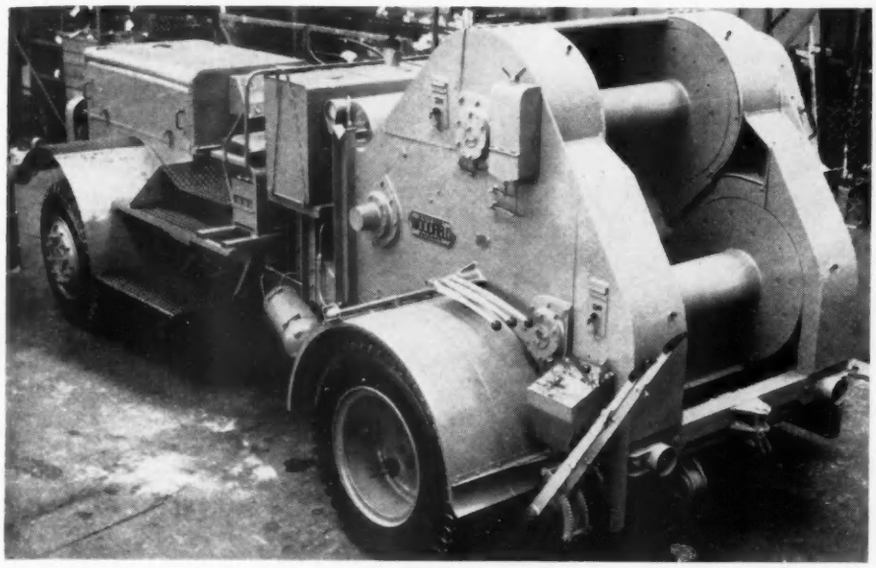
For more data, circle E14 on postcard



New Plastic Tank

This new fiber glass plastic tank has cut costs of salt water distillation units and reduced maintenance problems. A constant supply of fresh, soft water at economical price now is within reach of all off-shore oil rigs. The 750-gpd unit is little more than 3 feet high and fits into small quarters. (Maxim Division of Emhart Manufacturing Company).

For more data, circle E15 on postcard



Well Servicing Hoist

A new model well servicing hoist known as the Fieldmaster TC has been produced and tests completed. Fieldmaster TC is supplied with a single stage Twin Disc torque converter resulting in ease of control throughout the range of the hoist operations and providing a shock absorber element throughout the transmission which should materially reduce the wear and tear on chains and sprockets and other accessories. (Woodfield Rochester Ltd. Supplements data on Pages 5853-5872, 1960-1961 Composite Catalog.)

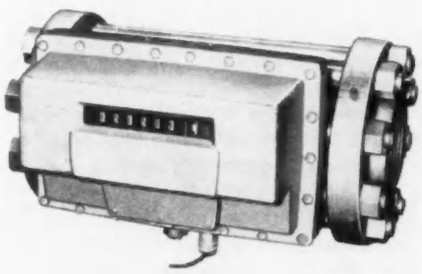
For more data, circle E16 on postcard

PERFORATE TUBING IN THE WELL

KINLEY TUBING PERFORATOR

J. C. Kinley Co. Licensees

ABILENE, TEXAS—Hudson-Eads, Inc....OR 2-5331
ANACO, ANZOATEGUI, VENEZUELA
Anzoategui Wire-Line Service, C. A.
BAY CITY, TEXAS—J. P. Graham.....CI 5-4526
CABIMAS, ZULIA, VENEZUELA
Wireline Engineers, S. A.
CASPER, WYOMING—C. A. White.....3-5264
CORPUS CHRISTI, TEXAS—Tolle, Inc...TE 5-5367
CORPUS CHRISTI, TEXAS
J. D. Ball Wire Line Service Co.....TU 3-7762
FARMINGTON, NEW MEXICO
D & R Service, Inc.....DA 5-2393
FORT MORGAN, COLORADO—C. A. White....919
GLENDIVE, MONTANA—C. A. White...EM 5-3833
HOBBS, NEW MEXICO
Horne Well Service Co.....3-5396
HOUMA, LOUISIANA
Assoc. Eng. & Equip., Inc.....UP 2-0347
HOUMA, LOUISIANA—Camco, Inc.....7330
HOUMA, LOUISIANA
Fred Haynie Oil & Gas Well Service...UP 3-7885
HOUSTON, TEXAS
Mid-Western Well Ser. Co.....RE 4-4262
HOUSTON, TEXAS
Long Line Production Control.....GR 3-5739
LAFAYETTE, LOUISIANA—Camco, Inc. CE 5-3124
LIBERAL, KANSAS—Rainbo Service...Main 4-3598
MIDLAND, TEXAS
Luccous Service & Eqpt. Co.....MU 2-8311
NEW IBERIA, LOUISIANA
Cardinal Wireline Specialists, Inc.....EM 4-5165
NEW IBERIA, LOUISIANA
Klein-Deco Wire Line Service.....EM 9-6632
ODESSA, TEXAS
Camco Wire Line Service, Inc.....FE 2-6497
ODESSA, TEXAS
John Kuykendall Wireline Service Co...FE 7-7210
OKLAHOMA CITY, OKLAHOMA
Rainbo Service Co.....ME 4-2131, ME 4-0105
PETTUS, TEXAS
Eddie Jones Eng. Co., Pettus 16, Beeville.FL 8-1218
SHREVEPORT, LOUISIANA—Camco, Inc.... 8-3615
VICTORIA, TEXAS—Camco, Inc.....HI 3-9521
WICHITA FALLS, TEXAS—Tudson-Eads, Inc.
322-8584, 322-1792, 767-8727, 723-4690, 767-3793



New Mass Flowmeter

A new mass flowmeter for natural gas has been jointly developed by BS&B and the General Electric Company. The "true mass" flowmeter makes possible the measurement of gas directly in pounds, eliminating calculations for conversion of volume to weight. A small gyroscope automatically totalizes the flow by integrating the torque with respect to time, permitting the output to be continuously summed up on a dial reading in pounds. (Black, Sivalls & Bryson, Inc. Supplements data on Pages 685-704, 1960-1961 Composite Catalog.)

For more data, circle E17 on postcard

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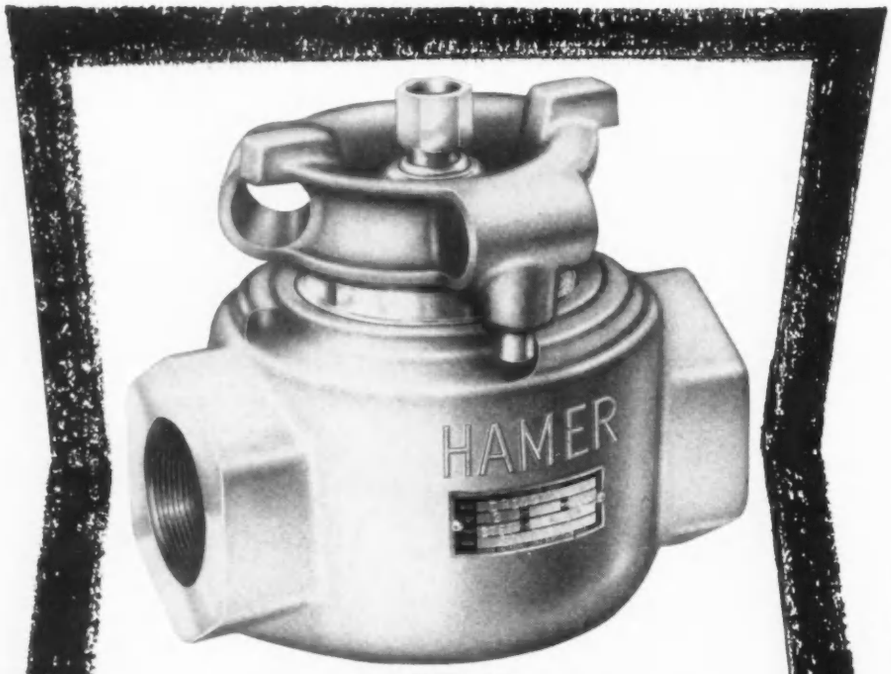

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for high pressure services
Hamer
D SERIES PLUG VALVE

Specially designed for high pressures (5,000 to 15,000 lb. CWP) the new Hamer "D" Series Plug Valve is unsurpassed for easy operation, positive shut-off, and long life in severe services. It has proved highly successful in service company operations handling slurries and abrasives at high pressures. It is ideally suited for hydrostatic test lines, high pressure flow lines, hydraulic applications, high pressure lines on drilling rigs, and wherever you have high pressure to control.

The cylindrical plug is precision finished and fitted in specially designed four-piece segments which provide a micro-floating action that prevents freezing or sticking under all operating conditions. The "D" Series Valve requires no adjustments and can be used in lubricated or non-lubricated service. It can be completely renewed in the line in a few minutes, with the replacement parts kit containing segments, plug, seals and gaskets.

● Ask your WECO Representative about additional advantages of using the new Hamer "D" Series Plug Valves in your high pressure services.

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WELL EQUIPMENT MFG. CORP.
HOUSTON, TEXAS
Division of CHIKSAN COMPANY *a subsidiary of* FOOD MACHINERY AND CHEMICAL CORPORATION
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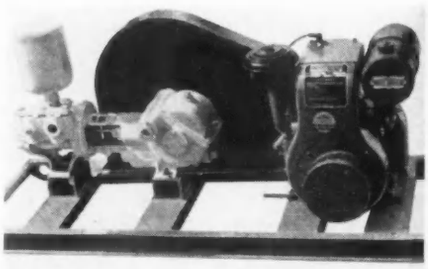
WECO UNIONS · CHIKSAN SWIVEL JOINTS · HAMER LINE BLIND VALVES · HAMER PLUG VALVES

New equipment

Portable Viscometer

A completely portable viscometer with a hand-cranked drive has been made available. Outstanding feature is the drive's constant high-low speed ratio which makes possible accurate measurements by the two-point method. Ideal for field service because it eliminates the need for bulky storage batteries and power packs. Designated Model HC34, the viscometer is available as a complete instrument or as a conversion unit for Fann Model 34. (Fann Instrument Corporation. Supplements data on Pages 1830-1833, 1960-1961 Composite Catalog.)

For more data, circle E18 on postcard



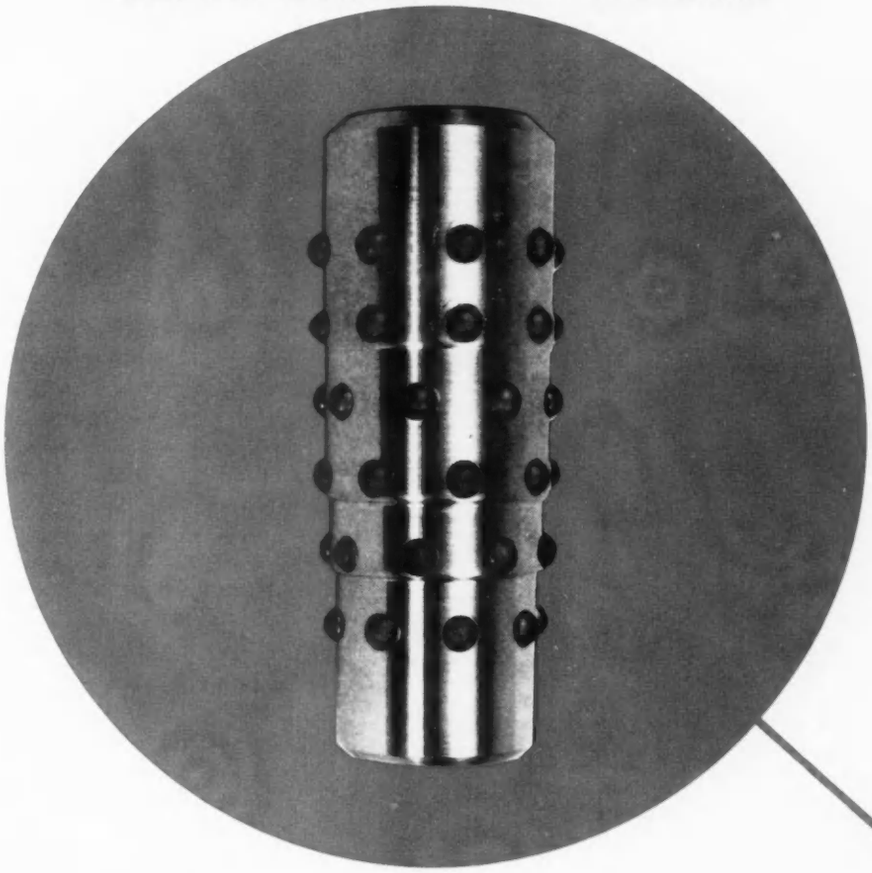
Newly Designed Pump

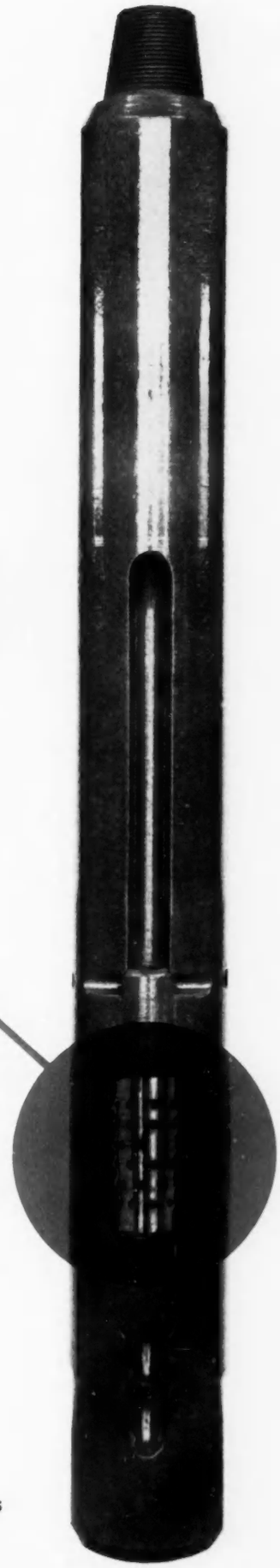
The Harley 7,400 pump on this unit is a newly designed single cylinder, double acting, reciprocating type and is made in one size only. Fluid end is made of ductile iron (nodular iron) and has a tensile strength of 30,000 psi and 15 percent elongation. Piston cylinder is made of steel, covered with smooth non-corroding porcelain and it is easily replaced or removed for inspection. Air chamber is of heavy steel and has a high safety factor. (Harley Sales Company.)

For more data, circle E19 on postcard

TUNGSTEN CARBIDE COMPACTS MAKE THE DIFFERENCE!

KNOBBY
CUTS REAMER COSTS





Reamer costs in hard formation areas are being reduced as much as 70% by Drilco's NEW and EXCLUSIVE Mark VI Knobby Reamer Cutter —the only reamer cutter using Tungsten Carbide compacts.

Performance comparisons prove that one set of **Knobby** Cutters will outlast five to ten sets of conventional cutters . . . and the **Knobby** insures you of a full gage hole all the way.

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New literature

To get your copies, circle key numbers on postcard and mail to WORLD OIL.

Cement Equipment Brochure

Dowell has issued a brochure on its new cementing equipment. Description, photographs and important features of the units are included.

To get a copy, circle E20 on postcard

Unit Pumpers Booklet

Continental-Emsco has published a booklet describing its full line of unit pumpers, including seven recently added sizes. Brochure is complete with rating charts, dimensions and specifications. Illustrations include new design features, one-man counter-balancing method and typical prime mover mounting. Also includes information on load multiplication factor and its effect on power costs and wear.

To get a copy, circle E21 on postcard

Strata-Crete Bulletin

The Strata-Crete Department of Great Lakes Carbon Corporation has published a new bulletin entitled "How to Cut Oil Well Cementing Costs" describing many of the advantages attributed to Strata-Crete 6 as an additive for oil well cements. Bulletin includes technical data on Strata-Crete 6 as well as a complete job report on the results obtained with the new additive in a Louisiana field.

To get a copy, circle E22 on postcard

Dipmeter Booklet

A booklet describing the Continuous Dipmeter and the broadened application which is increasing the use of dipmeter surveys for obtaining more detailed geological information is available from Schlumberger Well Surveying Corporation.

To get a copy, circle E23 on postcard

Derrick Lighting Publication

An eight-page publication designed to serve as a ready reference to assist an operator in the selection of derrick lighting systems and components has been published by Hutchison Manufacturing Company. Publication covers systems and components for all derricks and masts. Also, gives complete, detailed information as to the exact type of light or component needed.

To get a copy, circle E24 on postcard

Mud Systems Booklet

A six-page bulletin covering complete mud systems and their components is available from the manufacturer, Joe Stein, Inc. Shown are specialties in gate valves, check valves, a variety of steel mud pits and information as to usual arrangements and operation of equipment.

To get a copy, circle E25 on postcard

Steel Houses Brochure

A four-page brochure covering a line of portable steel houses is available from Joe Stein, Inc. Brochure includes knock-down types for export, trailer-mounted units, utility houses and special fabrications up to 52 feet in length.

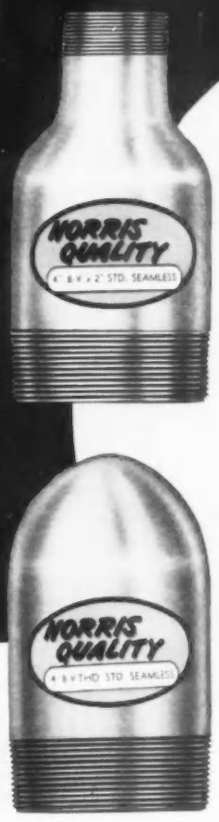
To get a copy, circle E26 on postcard

Tubing Cutter Booklet

A four-page colored bulletin No. 801 on the Chemical Tubing Cutter has been released by the McCullough Tool Company. Full illustrations, specifications, performance and operating advantages are explained.

To get a copy, circle E27 on postcard

Always at your Supply Store



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